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SECTION 16

POWER-SYSTEM OPERATIONS

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16.1 THE ENERGY MANAGEMENT SYSTEM

16.1.1 Introduction

The management of the real-time operation of an electric power network is a complex task requiring the interaction of human operators, computer systems, communications networks, and real-time data-gathering devices in power plants and substations. There are several concerns that operations departments must take into account in the operation of an electric power system. First and most important is the safety of its personnel and the public. This requires that steps in switching the network be made in accordance with safety procedures so that the lives of utility personnel in the affected substations are not endangered. Next, operating departments are concerned with the security or reliability of the supply of electric energy to customers. In most modern societies, the continuous supply of electric energy is extremely important, and any interruption of a large number of customers at one time is considered an emergency. Finally, the operations department is charged with operating the power system as economically as possible within safety and security limits.

This section deals with the systems that are used to manage a modern utility network. Such a system is usually called an *energy management system* (EMS) and consists of computers, display devices, software, communications channels, and remote terminal units that are connected to control actuators and transducers in substations and power plants. Broadly speaking, these systems are broken down into the following tasks:

- Generation control and scheduling
- Network analysis
- Operator training

The task of managing the generation of a large power system starts with the control of generation to maintain system frequency and tie-line flows while keeping the generators at their economic output. To this are added the economic dispatch, which determines the most economic output of each generator for a given load, the on/off scheduling or commitment of generators to meet varying load demands, and the determination of the pricing and amount of energy to buy and sell with neighboring utilities.

The task of managing the transmission system network requires the monitoring of thousands of telemetered values, the estimation of the electrical state of the network given the telemetered values, and the estimation of the effect of any plausible outage on the operation of the network. The security-analysis problem requires that the EMS be capable of analyzing hundreds or thousands of possible outage events and informing the operator of the best strategy to handle these outages if they result in an overload or voltage limit violation.

The operators must be highly trained in the use of the EMS and how to respond to emergencies. To be sure that operators are trained effectively, most utilities incorporate a simulator into their EMS that is capable of simulating the effects of an emergency on the power system. The operator is then required to “respond” by taking actions on the simulator that corrects the emergency problem. In this way new operators can be introduced to emergency procedures and experienced operators can have their training refreshed.

The EMS systems now in use in a modern power-system operations department are very large computer systems that require a large maintenance staff. The EMS is usually one of the largest computer systems in use in a utility company and often has within its database the needed information for many of the other engineering and design departments. In recent years, the concept of open systems has taken hold within utility EMS systems so that they are approaching a truly distributed form of command and control system.

16.1.2 Overview of Energy Management System Functions

Supervisory Control and Data Acquisition (SCADA) Subsystem. Supervisory control supports operator control of remote (or local) equipment, such as opening or closing a breaker, with security features, such as authorization and a select-verify-execute procedure. The data-acquisition subsystem gathers telemetered data for use by all other functions within the EMS. Data are obtained from various sources including remote terminal units (RTUs) installed in plants and substations and devices near to the system control center by local input-output (I/O) equipment.

A SCADA system provides three critical functions in the operation of an electric utility network:

- Data acquisition
- Supervisory control
- Alarm display and control

Data-Acquisition Function. The data-acquisition subsystem periodically collects data in processed or raw form from remote terminal units. Data acquisition consists of five functional areas:

- Data collection
- Data processing
- Data monitoring
- Special calculations
- Scan configuration control

Data collection is responsible for periodically acquiring data from remote terminal units at the appropriate rate. In addition, data collection monitors the various scans to make sure they initiate and complete within the current time period.

Data processing is responsible for converting analog values from raw data to engineering units. It is also responsible for converting digital status points to a system convention of device states (0 for closed and 1 for open). Data for points that are manually replaced in the database are not usually processed. Data processing is also responsible for handling data obtained from data links to other computer systems.

Data monitoring interfaces with the alarm processor and notifies it when the following occur:

- Devices change state
- Values exceed operating limits

Data monitoring also provides deadband and return-to-normal features.

Special calculations support various standard calculations such as

- Copy a value
- MVA from MW and Mvar measurements
- MVA from kV and amperes
- Amperes from MVA and kV measurements
- Other common periodic calculations

Calculated values are derived periodically from scanned data in the database.

Scan configuration control removes a terminal unit from the scan or switches the channel assignment when sustained communications errors occur. Scan configuration control periodically attempts to reestablish communications with terminals, which have been removed from the scan.

Supervisory Control Function. This function allows the operator to control remote devices and to condition or replace values in the database. All operations are multistep procedures. Selection of the device to be operated is the first step. Next is the visual verification step, and the final step is operator execution or cancellation. Data conditioning includes operations such as the following:

- Manual replacement of telemetered data
- Alarm inhibit/enable
- Reverse normal (change definition of the normal state of a device)
- Bypass enter (of failed telemetry)
- Tag/tag clear

Summary displays support the manual replace, alarm inhibit/enable, and tag/tag clear functions. Entries on these summaries are typically in inverse chronological order, the most recent entry being at the top of the summary.

Alarm Display and Control Function. The subsystem is responsible for the presentation of alarms to the operator. It supports alarm presentation and alarm presentation control. Alarm presentation is responsible for constructing the alarm message, organizing alarms in categories, maintaining an alarm summary display and abnormal summary, maintaining console logs, initiating audio/visual annunciators, and interfacing to other functions (e.g., the mapboard). Presentation control assigns priorities to alarm messages, recognizes points which are inhibited from alarming or manually replaced by the operator, and provides operator functions such as alarm acknowledgment.

User Interface Subsystem. The most visible feature of an energy management system is the user interface (UI) subsystem, which includes the following:

- Presentation of system data on visual displays
- Entry of data into the EMS through a keyboard
- Validation of data entry
- Support of supervisory control procedures
- Output of displays to a printer or video copier
- Operator execution control of application programs

Displays are created by using an interactive display builder, which allows definition of linkages between areas on the display and the EMS database for retrieval and entry of data. Also, the user can define function keys or function keys/display locations (poke points) when building a display to cause the presentation of another display or to initiate the execution of an application program.

The display builder allows the operator to create or modify the static elements of the display and add, modify, or delete the data and control linkages of the display. When the operator is satisfied with the display, the display definition is saved in the display file for later use by UI.

Displays are presented on a cathode ray tube (CRT) display at a console. An EMS console consists of one or more CRTs having full graphics capability, a display controller, a keyboard, and a trackball or mouse.

The flexibility in display format provided to the user allows a single subsystem to support a wide range of display types. These typically include

- Menu or index displays
- One-line schematic circuit diagrams

- System overviews
- Substation and generation displays
- Transmission line displays
- Summary displays
- System configuration displays
- Application program displays
- Trend or plot displays
- Disturbance data collection displays
- Historical data storage displays
- Report displays
- Other displays

Communications Subsystem. The communications subsystem encompasses management of a local-area network supporting the EMS itself, such as a dual-redundant Ethernet, token ring, or fiberoptic communications medium, and support of communication with other computing systems and field equipment.

In addition to the users within the control room, there may be schedulers, trainees, programmers, engineers, and executives who require access to the EMS through standard console displays, remote displays, or even personal computers. All these have to be connected to the EMS via a local area network that may extend outside the control center building to other facilities.

Other connections within the utility may include off-line engineering systems for planning or long-range scheduling, other control systems, for example, load management, distribution, or plant management, and control and corporate (billing and customer) computer systems. External communications are typically with other utilities or power pools.

Information Management Subsystem. The information management subsystem supports definition of and access to data used by the EMS. This includes all the static data descriptive of the power system, the EMS configuration, and data shared with other systems. It also includes organization of data for specific uses, for example, for data acquisition and monitoring and for network analysis algorithms.

In current EMS configurations, the database is distributed. This results in a need to facilitate data access without burdening either the operator or the applications programmers and other system users. Evolution of software standards and tools in the computer industry has led to products that support these needs, such as relational database managers and computer network file and resource managers.

Applications Subsystem. The applications extend the usefulness of an EMS, allowing data gathered by the SCADA system to be used to optimize and control the power system. An EMS overview is shown in Fig. 16-1.

Generation Control Applications. An interconnected system is made up of one or more control areas, each of which is defined as that portion of an interconnected system to which a common generation control scheme is applied. It also may be regarded as that portion of the interconnected system which is expected to regulate its own generation to follow its own load changes. It may consist of a single utility, or a part of one, or a whole group of pooled utilities. In each case, a control area would include all the generating units, loads, and lines that fall within its prescribed boundaries. All the control areas of an interconnection, taken together, should account for all the generation, load, and ties of the interconnected system.

A single-area system is one in which the entire interconnected system is encompassed within one control area. One control system provides the basic regulation for the entire interconnection and does not distinguish between the locations of load changes within the interconnection. A multiple-area system is one in which there are many control areas, each with its own control system, each normally

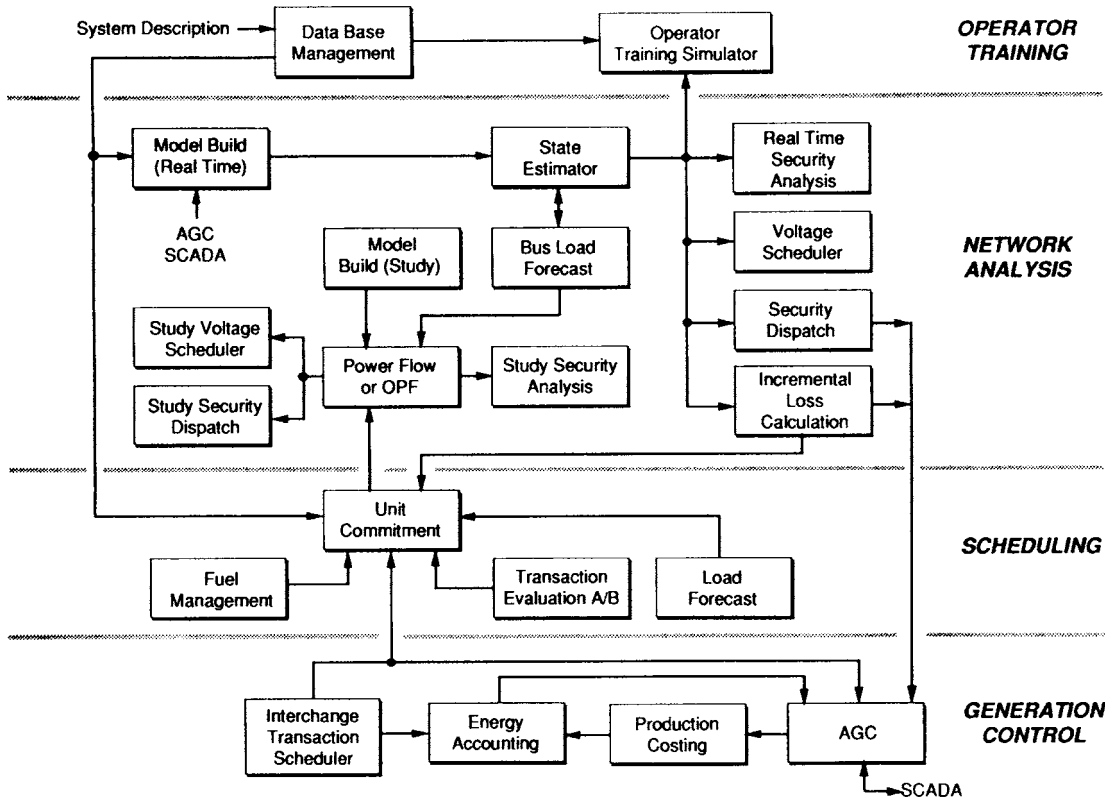


FIGURE 16-1 Energy management system.

adjusting its own generation in response to load changes within its own area. All the interconnected systems in the United States and Canada operate on a multiple-area basis.

Speed Governor. The generating unit's speed governor, along with governor-controlled steam valves (in a thermal plant) and a speed changer which provides for adjustment of the governor set point, constitutes the primary control loop for maintaining frequency at the unit level. The steady-state speed regulation characteristic of the speed governor relates a per-unit change in rated speed (y axis) to a per-unit change in rated load (x axis) and is a straight line with negative slope (called *droop*). Thus, with the speed changer set to provide rated speed for a given load, changing the set point shifts the straight-line characteristic along the x axis so that more or less output is demanded for constant rated speed. The automatic generation control (AGC) signal to raise/lower the set point (or signal for a directed set point) closes the system-level control loop and is also referred to as *supplementary control*.

Operating Objectives of Generation and Power-Flow Control. Automatic control of generation and power flow is an essential need for the smooth, neighborly, and effective operation of a wide-spread interconnected system. On a multiple-area interconnection, the regulating or control objectives are threefold:

Objective 1. Total generation of the interconnection as a whole must be matched, moment to moment, to the total prevailing customer demand. This in itself is achieved by the self-regulating forces of the system.

Objective 2. Total generation of the interconnected system is to be allocated among the participating control areas so that each area follows its own load changes and maintains scheduled power flows over its interties with neighboring areas. This objective is achieved by area regulation.

Objective 3. Within each control area, its share of total system generation is to be allocated among available area generating sources for optimum area economy, consistent with area security and environmental considerations. This objective is achieved by economic dispatch, supplemented as required by security and environmental dispatch.

The means of achieving objectives 2 and 3 are referred to as *supplementary control*, or currently—and more generally—as AGC. Such control may be regarded as a reallocation control redistributing the systemwide governing responses to load changes in various areas to generators within the areas that had the change. Each area then follows its own load change, with scheduled internal distribution. On a single-area system, objective 2 does not apply.

These functions act at the overall system level to regulate the real power output of generation, economically allocate demand among committed units, calculate various reserve quantities, determine production costs, and account for interchange of power between utilities and/or control areas.

Automatic Generation Control. Automatic generation control, sometimes called *load-frequency control* (LFC), regulates power system in terms of maintaining scheduled system frequency and scheduled net interchange. Automatic generation control is implemented as a closed-loop feedback controller. The error signal is determined either as a computed area control error (ACE) for a control area or a given area requirement (AR) in some power pool control structures. Positive ACE indicates overgeneration; positive AR indicates undergeneration. The ACE calculation is based on frequency deviation from schedule, net interchange deviation, or a composite tie-line bias. In tie-line bias control mode, interconnected control areas jointly participate in maintaining frequency, which is uniform among areas, but are individually responsible for maintaining each area's scheduled net interchange. The formula for this is

$$ACE = B(f_{\text{actual}} - f_{\text{scheduled}}) + (\sum TMW - I_{\text{scheduled}})$$

where the summation is over all tie-line megawatts (TMW), I is the current scheduled net interchange level, and B is tie-line bias, which converts frequency deviation to real power, usually expressed as MW/tenth Hz. B is characteristic of the installed capacity (MW) of the control area and is usually a constant. Additional terms or modifications to the formula are used to account for correction of time errors, inadvertent interchange payback, and so on.

Area control error is a noisy signal and so requires processing. Processing also includes provision for proportional, integral, and anticipatory (or derivative) control characteristics for AGC as a feedback controller. Integral control is necessary to prevent long-term offset in frequency and to ensure that ACE crosses zero (the normal set point) frequently. System control requirements thus determined from processed ACE are allocated to generating units based on several criteria.

Unit Control Considerations. Key considerations are

- The deviation in each unit's loading from the most recent economic assignment—MW level
- The deviation of total system load since the last economic dispatch
- The current value of ACE

Economic base points are assigned by the economic dispatch (ED) function, and LFC will drive unit loading toward these assignments unless there are overriding conditions. This mode is termed *mandatory* unit control (mandatory with respect to economics).

An overriding condition may be that ACE exceeds a threshold beyond which correcting ACE takes precedence. In this case, AGC is operating in a *permissive* mode (with respect to economics). Here units are inhibited from moving against correction of ACE. If ACE exceeds a larger threshold, an *emergency assist* mode is entered. Here all units move to correct ACE and may move against their economic directions, that is, away from economically assigned base points.

Units participate in ACE reduction in proportion to regulating participation factors, which may be operator-entered or calculated from various criteria according to individual company or pool operating policies. Units participate in adjusting to the deviation in system load since the last ED by use of economic participation factors, produced by ED. In some systems, a single set of participation factors is used.

Unit desired generation is calculated according to the preceding rules, and control output is sent to generating station RTUs either as MW set points or raise/lower signals as appropriate to the local generating unit plant-control equipment.

Control of each unit assigned to automatic regulation is performed by a separate unit-control loop (feedback controller). Here the set point is unit desired generation already obtained. Models of individual unit dynamic response to previously issued control commands are compared with actual telemetered output of the unit in determining the degree of new control to be issued.

AGC Operator/Dispatcher User Interface. Typical AGC displays used by system operators include

System summary—provides an overview of system control information such as area control error, reserve quantities, incremental costs, lambda (from ED), and AGC control mode states and allows the operator to change these states or enter key parameters.

Generation summary—summarizes current status and output of all generating units and may provide for operator changes to unit status.

Station/plant summary—shows detail related to operation of individual units, limits, fuels, costs, and so on.

Tie-line summary—shows telemetered real and reactive power flow on all tie lines and net total real power interchange and may show line limits.

Figure 16-2 shows an overview of a typical AGC program.

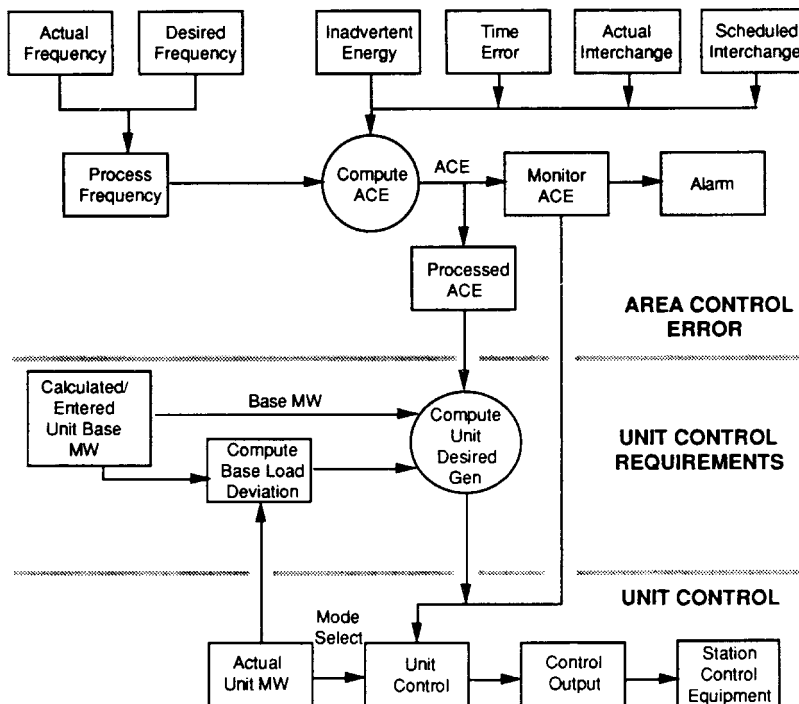


FIGURE 16-2 Overview of an automatic generation control system.

Interchange Scheduling. The interchange transaction scheduler (ITS) function supports the operator in entering (defining), editing, and reviewing power interchange schedules with neighboring control areas/utilities. The schedules are usually negotiated by the operator over the telephone with other operators in control rooms at other utilities. These schedules are utilized principally by AGC and energy accounting.

Schedules are established by utility and by account within each utility. Examples of accounts include firm or nonfirm energy and capacity purchases, sales, and so on. Schedules may be defined on a daily hour-by-hour basis or on a start/stop date and time basis according to company or pool operating procedures. Various entry displays support definition of such schedules. Other displays are used to summarize transactions by company, account, or chronology.

Given a multitude of concurrently active transactions, a net profile of interchange is constructed in order to provide AGC with the instantaneous net scheduled interchange needed for real-time system regulation. At the end of each hour, scheduled transactions are compared with actual data in the energy accounting function to maintain historical records.

An emergency scheduling capability allows the operator to enter a single net schedule of interchange to override all other currently active schedules. Other entries associated with transactions may include cost, price, ramp rates (MW/minute), and additional information associated with third-party or "wheeling" transactions.

Economy A Transaction Evaluation. Economy A Transaction Evaluation is a user-oriented program for evaluating short-term interchange transactions with a neighboring utility. It applies to transactions, which do not involve altering the commitment of generating units.

The idea behind Economy A transactions is to find an amount of power to interchange with a neighboring system so that both systems achieve maximum benefit. Essentially, this means that the system with lower incremental cost of generation will sell power to a neighbor with higher incremental cost. The optimal amount of power interchange is that which brings the two systems to the same incremental cost.

To find the optimal interchange, agreed increments or blocks of interchange are added or subtracted to the base economic dispatch. For each block, a price or cost increment is calculated. The operators in each system then use the block information to determine the number of blocks to use in reaching a final interchange value.

The program also can use the economic dispatch package in a study mode to calculate incremental and production costs under a variety of conditions specified by the operator. Parameters for these calculations can include generation conditions, interchange schedules, and unit costs.

Input. Economy A obtains the following from automatic generation control:

- Economic and operating limits, mode, and assigned or base generation
- Fuel costs
- Starting megawatts
- Efficiency factor
- Heat-rate curve selection

Operator inputs consist of requests, modification of the preceding data, and definition of the transaction and system parameters.

Output. Results of Economy A Transaction Evaluation are presented in CRT displays and also can be sent to a printer. This output includes

- System results, such as production costs, spinning reserve, and incremental losses, for each block evaluated
- Economically assigned generation for each unit

Energy Accounting. The energy accounting (EA) function maintains accumulated operating data in accounts ordered on an hourly, daily, monthly, and/or yearly basis. These accounts typically relate to energy exchanged via tie lines, plant generation, large-customer consumption, and on/off peak cumulative inadvertent energy exchanges. Additional data such as production costs or purchase/sale costs also may be accumulated, and in a hydroelectric system, discharge of water or pond levels may be recorded. In practice, generalized calculation and report functions are configured to provide energy accounting capabilities.

Accumulating energy data is accomplished either by field equipment such as pulse accumulators (counters) which provide energy data to be telemetered or by telemetering power (megawatt) values to the EMS, where these are integrated to obtain energy data (MW-hours).

Daily power system values are collected on an hourly basis. Correspondingly, monthly values are collected and stored once a day so that there is a value for each day of the month. The following paragraphs describe typical energy accounting processing that is performed on either a daily or monthly basis.

Daily Features. Energy accounting collects the instantaneous tie-line megawatt values every minute and at the end of the hour produces the integrated values for all tie lines. It then subtracts these values from the corresponding tie-line pulse accumulator values and stores the difference. The absolute difference is compared with a tolerance (for each tie line). This allows the accuracy of tie-line telemetry information to be continuously monitored.

Energy accounting maintains actual tie-line data for each hour of the day. It also classifies the values according to whether the hour of the day is an off-peak or on-peak hour. On-peak and off-peak start and stop times are defined via the information management function. Holidays and Sundays are considered off-peak. This allows interchange (both actual and scheduled) and inadvertent calculation to be divided into on-peak and off-peak accumulations. Daylight savings time conversion days (23-h or 25-h days) are also supported. For these days, the appropriate amount of data is collected and processed accordingly.

At the end of each hour, the hourly actual interchange values collected are added into running totals of on-peak and off-peak energy (depending on the hour). The scheduled interchange values provided by ITS are also added to on-peak and off-peak accumulations. Following the accumulation of interchange (scheduled and actual), the inadvertent energy for the hour is computed as the deviation between actual and scheduled interchange.

The inadvertent energy value for the hour is then saved. The hourly value is then used to update the cumulative (on-peak or off-peak) inadvertent energy value. The appropriate cumulative inadvertent energy value is then made available to AGC.

Energy accounting also may collect and maintain production cost data for each hour of the day. At the end of each hour, the production cost data for each generator and the system are collected and stored. Additionally, energy accounting supports the calculation and storage of system net generation and control area net load for each hour of the day. For all values maintained on a daily basis, the running daily total for each quantity is also updated and retained.

Production-Cost Calculation. Production costing (PC) calculates the hourly production cost for each generating unit and the entire system. Production costing is synchronized with execution of the economic dispatch program and supports the following features:

Production costing executes periodically throughout the hour, and the average hourly production cost is calculated at the end of the hour.

Several sets of production cost values can be calculated from the current actual unit generation levels and for the generation levels recommended by the economic dispatch.

System dispatch performance is monitored by computing actual generation costs, dispatched production costs, and ideally dispatched production costs (manual dispatch).

A set of unit fuel consumption values can be computed from actual unit generation values.

Unit and system daily logs are provided showing all relevant hourly and daily values via the energy accounting and reporting support functions.

The periodic production costs are calculated by integration of the area under the incremental cost curves or by separate I/O curves and can include the effect of incremental and fixed maintenance costs, fuel cost, and efficiency.

The periodic unit actual fuel consumption is calculated and includes the effect of the unit's efficiency. The unit actual fuel consumptions are summed to yield the current system fuel consumption. All unit production costs are summed to give the system production cost values.

The periodic values are integrated over the hour to produce hourly unit fuel consumption and production cost values. The hourly production costs and fuel consumption values are saved at the end of each hour. These values are then stored in a historical database by energy accounting.

Generation Scheduling Applications. The forecast and scheduling applications within an energy management system gather, organize, and use large amounts of historic and economic information. This group of related software packages puts that information to work in forecasting loads, scheduling units and generation, evaluating Economy B type transactions with other utilities, and tracking fuel contracts. Forecast and scheduling applications are tailored to the power system they serve. For example, a unique load forecast model is developed for each case.

Load Forecast. This program forecasts hourly loads 1 to 7 days in advance. Load-forecasting methods are based on similar days according to season, day of the week, and so on, with further adjustment for weather effects by using

- Nonlinear, dynamic, adaptive weather model
- Correlation of load to temperature, humidity, light intensity, and wind speed
- Adaptation to real-time load and actual weather conditions

Unit Commitment. This program schedules hourly status (on line/off line) and output for each on-line unit, 1 to 7 days in advance. The calculations consider

- Production cost models
- Start-up cost model
- Shutdown cost
- No-load (spin) cost
- Incremental maintenance costs
- Network losses

Unit commitment runs with two sets of constraints. System constraints are

- Load forecast
- Interchange schedules
- Reserve requirements
- Regulation requirements

Unit constraints are

- Prescheduled status or output
- Derations
- Multiple limits
- Rate limits
- Up- and downtime limits
- Reserve limits
- Plant start-up limits

Each unit can be assigned these models

- Thermal
- Combustion turbines
- Combined cycle
- Ramping times
- Start times
- Multifuel

Economy B Transaction Evaluation. Economy B transactions are similar to Economy A except that generating units must be added or taken off line to meet the contract. This program does a before-the-fact evaluation of proposed interchange transactions. After the fact, it can make the same analysis to evaluate the worth of each transaction. It can

- Perform multiple commitments against levels of prioritized interchange
- Recommend prices
- Make buy/sell analysis
- Use fixed, operator-entered, or variable prices

Fuel Management. The fuel-management programs incorporate fuel constraints into unit commitment schedules so as to optimize the use of fuel contracts. Contracts can be

- Take or pay
- Fixed price
- One hour to one month

Contract limits can be

- Hourly to monthly
- Rate of consumption
- Total consumption

Network Analysis Applications. These monitor the security of the system and assist the operator in optimizing system performance. The *model-build program* responds to switching operations in the transmission system. With this information it determines the current network configuration. This constantly updated real-time model is used by other network analysis programs.

Inputs to the program are all measurements (including MW, Mvar, kV, and amperes), zero injections, and calculated loads. The *state estimator* uses statistical methods to check for bad data and to establish a consistent network solution as a basis for security analysis and power flow studies.

The *bus-load forecast* provides a forecast for each individual bus, for any specified hour of the week. Forecasts are based on the history of user-defined load groups. Both MW and reactive ratio histories are used. This information is used for studies and also can be used to support temporarily outaged telemetry.

Voltage scheduling is an optimization program that minimizes power losses in the system by adjusting unit voltages, load tap changing (LTC) taps, and phase-shifter taps. The program performs this optimization while maintaining voltages and Mvars within permissible ranges.

Optimal power flow (OPF) enables the operator to study a network solution, which describes the steady-state power flow that would result from specified network conditions. It can optimize system variables to enhance power system security and/or economy.

Security analysis determines the security of the power system under specified contingencies. It stimulates the steady-state power flow for each case and then checks for out-of-range conditions. Security analysis also handles split bus, altered topology, and islanded systems.

Security dispatch detects overloads in the real-time network model and determines control actions such as generator shifts that will alleviate the overload or that will avoid an overload after a contingency. The program can incorporate phase shifters, interchanges, and load shedding as well as unit outputs to solve problems.

Operator Training Simulator. With an operator training simulator (OTS), it has become possible to improve the quality of training for power system operators. The OTS allows operators to be exposed to simulated power system emergencies and to practice alleviating these emergencies. Similarly, operators may practice system restoration under simulated conditions. Since operators may be exposed to simulated emergency and restorative conditions on the OTS, frequently and at will, as opposed to rarely and by chance on the job, the time required to train a new operator may be significantly shortened. Similarly, with an OTS, it becomes possible to expose experienced operators to emergencies and restoration procedures as part of refresher training.

The simulator can present results to the operators, which are as accurate as those observed by the EMS using typical power-system telemetry. The operator uses a user interface and applications functions which are identical in the OTS and in the EMS.

The OTS includes long-term dynamic models of the electrical network, loads, generators, turbines, and boilers. The OTS also includes the control functions of the EMS: SCADA, power applications, and their user interface. In addition, an educational subsystem is provided with features that allow the instructor to construct groups of one or more training events or power system disturbances and to store and retrieve these groups of events.

Other significant features of the OTS include

The power-system model in the OTS is the same as the model used in the EMS.

The OTS uses multiple consoles to support team training and an instructor position.

The OTS supports a load model which includes the effect of frequency, voltage, load management, and subtransmission reactive shunts and taps.

The OTS supports system restoration/blackstart exercises.

Underfrequency load shedding is modeled in the OTS.

The OTS allows representation of a wide range of power-system events or disturbances.

The OTS may include a model of the AGC systems of external companies.

The OTS includes relay models for over/undervoltage, inverse time overcurrent, over/underfrequency relays, synchro check relays, time switching, volts/Hz, over/underexcitation, and automatic reclosure.

The OTS includes features that allow the instructor to play the role of power-plant operators, substation operators, and neighboring company operators.

OTS Functional Description. The overall simulator system can be logically divided into four principal subsystems: the power-system model (PSM), the control-center model (CCM), the educational system, and the user interface.

The PSM simulates response of load, generation, and network conditions (flows and voltages) to control actions, which were initiated either by the operator or by AGC, and to preset events from the training system. The PSM includes a load-model program, network modeling, which is implemented as a network topology processor, and a fast decoupled load-flow algorithm and a set of prime mover models and frequency-response programs. The control-center model includes a replica of the control functions in the EMS. Included are the SCADA/AGC functions and selected network analysis functions. The educational subsystem provides a means for sequences of events to be defined, stored, and retrieved by the instructor. Separate displays are used to define each sequence and to catalog by title those presently stored. The user interface relates to all the previous subsystems. It provides display and control, via the workstation display and keyboard, and logging of all system events.

The operator simulation process differs from the operating models primarily in the time frame considered. Transient time scales are on the order of cycles (0.016 s), and longer dynamic stability

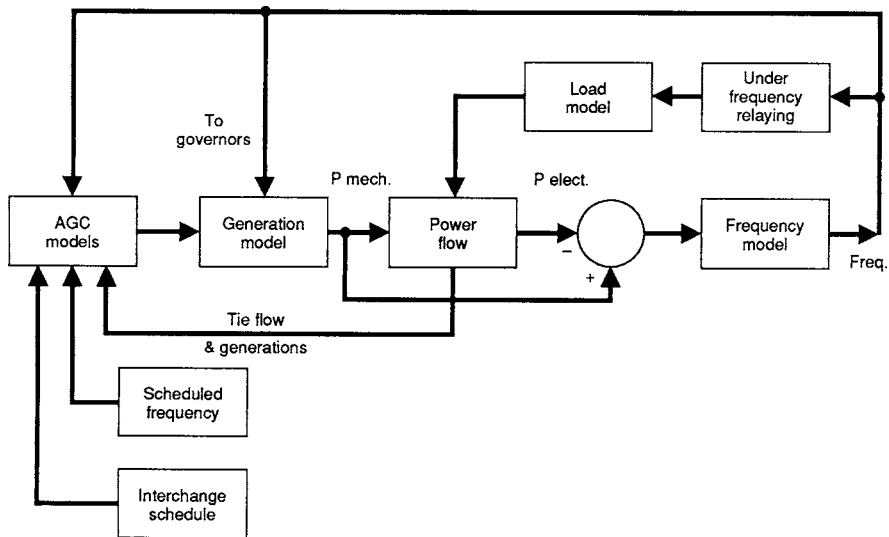


FIGURE 16-3 OTS control-response model.

runs last only a few seconds. The time frame for response of human control actions is the determining factor in the design of the simulation. Events that are beyond the range of human perception are not of interest, especially when viewed by telemetry with 10-s scans and through workstations with sampling of about 2 s. At the other extreme, it is important that the simulation be run in real time and be economical for runs of a half hour or more. These considerations result in an emphasis on prime mover dynamics and system frequency behavior in the structure of the simulation.

Because of the time response of AGC and operator control, we are dealing with low-speed phenomena rather than the transient and synchronizing effects not observed by the controller (either AGC or human). Also, because of the requirement for real-time response of the simulated power system, extensively detailed models of components with small time constants would require a short integration time step and a correspondingly heavy computational burden, so in this case we require a rather coarse time step (1 s) as compared with transient stability.

During steady-state operation conditions, line flows and losses are the result of generation, excitation, and load. The network solution is, therefore, more than adequately modeled by an efficiently coded load flow. A schematic of the control-response model is shown in Fig. 16-3.

16.2 RELAYING AND PROTECTION

By GUSTAVO BRUNELLO

The fundamental concept of protective relaying is to detect and isolate faults and other destructive phenomena in the shortest possible time consistent with economics and security. The principles vary at different points in the power system because of differing constraints. Distribution-system relaying must coordinate with fuses and reclosers for faults while ignoring “cold-load pickup,” capacitor bank switching, and transformer energization.

Transmission line relaying, on the other hand, must be sufficiently discriminating to locate and isolate any type of fault and do so with sufficient speed to preserve stability, to reduce fault damage, and to minimize the impact on the power system. This dictates the use of one or more pilot relaying systems.

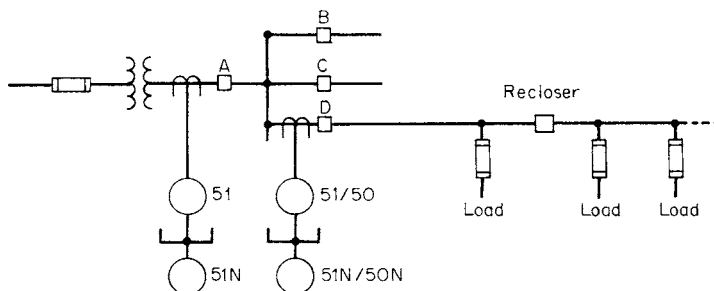


FIGURE 16-4 Typical distribution circuit relaying.

Subtransmission relaying varies from complete pilot relaying to simple directional overcurrent relaying depending on the importance and general nature of the subtransmission system.

Distribution-System Relaying. Typical distribution circuit relaying is shown in Fig. 16-4. Only one set of feeder relays is shown. This arrangement would be repeated for each feeder. The time-delayed phase and ground relays 51 and 51 N usually have a high degree of inverseness in their current-time characteristic to coordinate with the fuses and reclosers that are farther out on the circuit. The instantaneous units 50 and 50 N are typically set to trip the feeder breaker and protect the fuses when a temporary fault occurs beyond the fuse. For this type of fault, the feeder is removed from service by a reclosing relay that allows the fuse to blow when reclosing into a permanent fault.

The 51 N relay must be set with care to avoid its operation on loss of single-phase lateral load when a fuse blows. The “normal” load unbalance can be controlled to a reasonable degree by carefully supervising the balance of load connected to each individual phase (usually a 4-wire circuit with line-to-neutral connected loads). The opening of a fuse to clear a fault, and thereby drop load associated with one phase, will produce a much higher than normal load unbalance. This must not be allowed to cause operation of the ground relay. Its sensitivity is largely regulated by this consideration.

Cold-load pickup is the phenomenon whereby a feeder being reenergized after a long outage will experience a load appreciably in excess of maximum steady-state load (as a result of loss of diversity by thermostatically controlled devices). The feeder relays must ignore this if sectionalized reenergization is to be avoided. The relays on breaker A in Fig. 16-4 provide primary protection for the bus and backup protection for the feeder relays and breakers. In general, they are time-delayed and coordinate with the feeder relays with the accepted sacrifice of clearing speed for bus faults. These phase relays provide some measure of thermal protection for the supply transformer.

Modern microprocessor-based systems contain not only the instantaneous and time-delay relaying described above but, in addition, may contain reclosing, instrumentation, and fault data storage facility.

Subtransmission Relaying. Loops and multiple power sources used in feeding loads from the subtransmission system usually dictate the use of directional overcurrent relaying, distance relaying, or pilot relaying. In general, a subtransmission system is not intended to transmit bulk power from one location to another. Multiple sources are used purely in the interests of continuity of service.

Figure 16-5 shows an example requiring directional overcurrent relaying. A fault on the upper line would cause equal currents to flow in relays A and B. For this fault case, it is desired that relay A trip and B restrain. A fault on the lower line also causes equal current to flow in relays A and B. For this case, it is desired that relay B operate and relay A restrain. These two cases produce requirements that are mutually exclusive using simple overcurrent relays. The requirements can be met with directional overcurrent relays. If directional, the A relays would respond only to faults on the upper line and the B relays only to faults on the lower line. Coordination between A and B then becomes unnecessary.

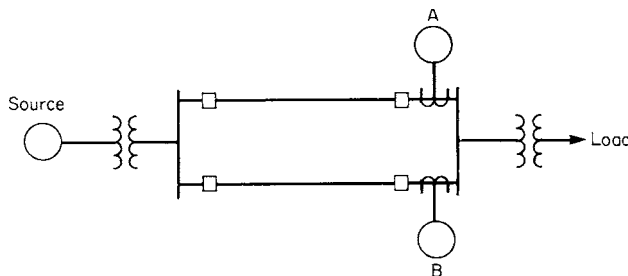


FIGURE 16-5 Partial one-line diagram of typical subtransmission system showing locations where directional relays are required.

Figure 16-6 defines in the simplest form a criterion for establishing where directional overcurrent relays are desirable.

Relay R in Fig. 16-6 requires consideration of distinctly different criteria, depending on whether instantaneous or intentional time delay tripping is involved. An instantaneous device at R must be set in such a way that it will never respond to a fault beyond bus B . The setting will be dictated by the maximum fault contribution (phase-fault contribution for phase relays or ground-fault contribution for ground relays or *phase relays*) for a fault at B and by the influence on the measuring unit of the dc component in the fault current. For example, a maximum fault at B , producing 20 A in relay R , would require a setting in excess of 20 A. If the maximum overreach factor for the particular instantaneous unit in use were 1.3 and a 10% margin were desired, a setting of $1.3 (1.1) (20) = 28.6$ A would be required.

If a reverse fault such as a fault near bus A on other circuits could cause current in relay R to exceed 20 A (symmetrical), a higher setting would be required for this instantaneous unit than 28.6 A because the same overreach and margin factors would apply.

Since the extent of line coverage is dependent on the setting of the device as well as the source-line impedance ratio, a reverse fault which dictated a higher setting would cause the extent of line coverage to be smaller. By using directional control, no consideration need be given to reverse faults.

If the magnitude of relay current for this maximum magnitude reverse fault were less than 20 A, no consideration need be given to the inclusion of directional control for the instantaneous unit. A nondirectional relay will be satisfactory in this application because the relative fault currents make the relay inherently directional.

Time-delay overcurrent relays differ in their criteria from those of the instantaneous unit. In the interests of backup protection, relay R should always be able to detect the minimum fault on and beyond bus B . Further, in any time-delay relay applications, this minimum case should produce an adequate multiple of pickup current in the relay to ensure a clearly predictable operating time.

If, for example, the minimum fault at B produced 14 A in relay R , a setting of 7 A would be required (to give a multiple of pickup of 2 for this minimum fault case). If a reverse fault could deliver current sufficiently large to cause operation of a relay set at this level, consideration should be given to the use of directional control of the time unit. A frequently used conservative summary of this concept is that if the maximum reverse fault current can exceed 25% of the minimum fault current at the next bus, use directional control.



FIGURE 16-6 Directional relaying criterion.

The combined criterion for these concepts is—use directional control if a reverse fault could influence the sensitivity of relaying used to detect forward faults or if selectivity would not otherwise be possible. If source variations restrict instantaneous coverage to less than 50% of the protected line, or if the tripping times realizable for time-delay relays become undesirably long, distance relays should be used.

Distance relays respond to the voltage and current applied to them and are usually more highly responsive at some lagging current angle. Figure 16-7 shows a typical R - X diagram that describes the behavior of these devices. Most distance relays in current use, phase and ground, have a characteristic similar to curve 1 or curve 2. Faults producing an apparent impedance at the relay location that falls inside the characteristic circle will cause the relay to operate. Since a distance relay has a distinct “reach” irrespective of source impedance and is directional, it is said to protect a “zone.” Zone 1 relays are set to cover a portion such as 80% to 90% of a subtransmission or transmission line. Zone 2 relays respond to faults at all locations on the line and also to others in proximity of the line end. This is shown in Fig. 16-8. Zone 2 relays are typically set to cover 100% of the protected line plus 25% to 75% of the shortest line departing from the remote bus. Since they overreach the next bus at the end of the protected line, they must have a time delay or be associated with a pilot relaying system in order to preserve selectivity with other relays. A zone 2 relay should not be set to overreach any zone 1 relay at the next forward station.

A zone 3 relay is also often used and may be directional in the same sense or opposite sense as the zone 1 and zone 2 relays, or in some applications may be nondirectional. Figure 16-8 shows a one-line diagram with a “reverse-looking” zone 3 relay. The user shall carefully verify that the impedance reach for zone 3 is less than the load impedance presented to the relay under the most unfavorable steady-state operating conditions (overhead and overvoltage) of the system.

Microprocessor-based distance relay systems provide multiple zones, complete phase are ground distance protection, plus pilot logic, instrumentation, fault-data storage, and oscillographic information. However, in the past, simplified distance-relaying schemes were sometimes used in the interests of economy. One type used a complete complement of relays for one zone, which was initially set for a zone 1 function. A “starting” unit (overcurrent or distance) used to sense the presence of a fault. After a time delay, the setting (reach) of the relay was extended to zone 2 and still later to zone 3 (forward). A further abbreviation of this scheme allowed the starting units to identify the type of fault and to connect the appropriate voltages and currents to a single distance unit. These systems vary substantially in complexity, redundancy, dependability, and cost. The choice of one system over the

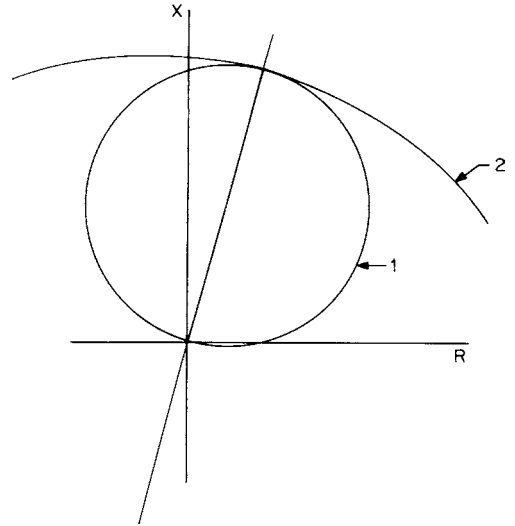


FIGURE 16-7 Resistance-reactance plot of distance relay characteristics.

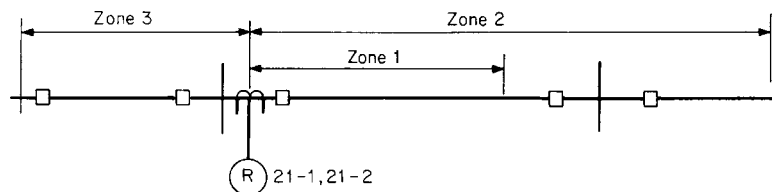


FIGURE 16-8 One-line diagram showing concept of distance relay zones.

others is dictated by the relative importance that is placed on each of these factors and the significance of the compromises involved in making such a choice.

Transmission Line Relaying. High-speed clearing of faults is universally required on transmission systems in the interests of maintaining stability, minimizing disturbance to wide areas of the power system, and decreasing fault damage. Pilot relaying is an important ingredient in this process. Pilot relaying entails the use of information obtained from one or more remote terminals as well as local information to establish the need to trip (or refrain from tripping) a local breaker. The remote information is transmitted by power line carrier, microwave, tones, pilot wires, optical fiber, or some combination thereof. An abundance of pilot-relaying systems are in use, each having its individual strengths and marginal weaknesses and each having varying degrees of dependence on the integrity of the channel.

Pilot Channels. Figure 16-9 shows one of the many types of pilot channels in use. This particular arrangement uses "power line carrier." The pilot channel is chosen sufficiently higher than the power frequency to allow separation to be achieved easily, generally 30 to 300 kHz.

Types of Protective Relaying Systems. Two basic systems form the nucleus for the families of pilot-relaying systems applied to transmission lines. They are the directional-comparison and the phase-comparison systems.

Directional-Comparison Relaying. The fundamental concept of the directional-comparison system is shown in Fig. 16-9. A directional relay at *A* responds to faults to its right as shown by the directional arrow in the figure. A similar relay at *B* responds to faults to the left of *B*. Both relays respond simultaneously only to faults on the protected line. The communication channel informs *A* about the state of *B*, and another informs *B* about the state of *A*.

One-to-one and a-half-cycle initiation of tripping is commonly achieved at both terminals following the occurrence of a fault on such a protected line. No tripping of these relays occurs for faults on other line sections. Abbreviated descriptions of the commonly used directional comparison schemes follow.

Directional-Comparison Blocking. In this system, each of the terminals is equipped with tripping and carrier-starting relays. The tripping relays are directional toward the protected line and are set to respond to all faults on the protected line and 25% to 50% beyond. This is called an overreaching setting. The carrier signal is required to prevent tripping for faults in that 25% to 50% overreaching area. Tripping at *A* is blocked by a signal transmitted from *B* and received at *A*. Transmission of the signal is initiated by a carrier-starting relay that operates for faults outside the protected line section.

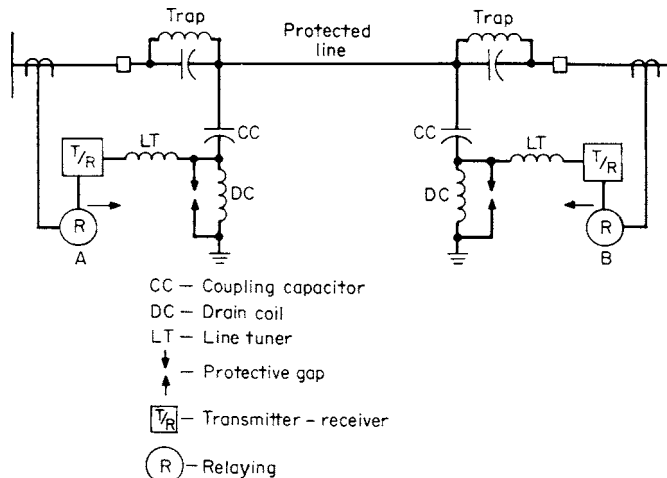


FIGURE 16-9 Representative channel for pilot relaying.

Internal faults are cleared by the tripping relays at all terminals, which have overriding control to stop all carrier transmission. A single-frequency on-off carrier may be used for both directions of transmission (A to B and B to A) because all carriers are turned off for an internal fault.

Underreach Blocking. This system uses a zone-extension scheme to limit, in the interests of economy, the number of distance units required. A relay set to cover zone 1 (the area from the relay location out to 80% or 90% of the protected transmission-line length) is stepped, after a coordinating delay such as 4 ms to zone 2 reach (covers the entire line) provided blocking carrier is not received from other terminals. If carrier is received, zone extension is still carried out, but at a much later time (often 15 cycles), to provide backup coverage for remote bus line sections and apparatus. Different carrier frequencies are required for the two carrier channels. Station A carrier cannot be allowed to block station A tripping because carrier cannot be stopped for some internal faults.

Acceleration. Zone extension is again used with this system. A frequency-shift carrier channel is preferred because transmission through a fault on the protected line may be required. A guard frequency is transmitted during nonfault conditions. The protective relays are given a zone 1 setting. All faults on the protected line are seen by one or both of the relays at the two ends of the line. Each causes carrier to be shifted to a trip frequency.

Receiving trip frequency causes the zone 1 setting of each local relay to be extended to zone 2 distance immediately. All faults in the area of overlap of the two zone 1 settings will be cleared without regard to the carrier signal. End-zone faults (faults not covered by the zone 1 relays at one of the terminals) will be cleared at high speed and essentially simultaneously once zone 1 extends to zone 2 reach.

Permissive Transfer Trip. In a permissive scheme, tripping occurs when the distance relay operates at each terminal and a trip signal is received at that terminal. The distance relays at the two ends of the line cooperate to clearly identify a fault as being “internal” to the protected line or “external.” Permissive transfer-trip relaying systems are identified as *overreaching* or *underreaching* system, depending on the setting of the directional distance relay that keys the frequency shift tone or carrier transmitter at each line terminal.

If the system has a setting that causes it to respond to faults on the protected line and additionally to faults beyond the end of the protected line, it overreaches the remote relay, and the system is identified as an *Permissive Overreaching-Transfer-Trip (POTT)* system.

Underreaching schemes have the distance relays set to respond to faults within 80% of the protected line length. When they operate, they key the frequency-shift channel transmitter from “guard” to “trip” as well as immediately tripping the local breaker(s) without regard to action at the remote terminal. The two categories of these systems are identified as *direct* and *permissive*.

In the *Direct-Underreaching-Transfer-Trip (DUTT)* system, receiving the channel trip causes tripping of the terminal breaker(s). No local fault-detector relay operation is required. Strictly speaking, the direct scheme is not a directional-comparison system, because operation of the zone 1 relay issues a command to trip all breakers associated with the protected line, and no comparison takes place.

In the permissive underreach scheme, a local directional distance element, that overreaches the remote terminal, is required to supervise the tripping. Each terminal has two measuring elements: a zone 1 distance that underreaches the remote terminal and a supervisory element that sees faults beyond it. This scheme is called *Permissive-Underreach Transfer Trip (PUTT)*.

Note that permissive transfer-trip systems require that a signal be received by the channel equipment in order for tripping to take place. These systems are usually committed to channels that are not dependent on the integrity of the protected power line itself such as pilot wires and microwave.

Unblock System. The unblock pilot relaying system is virtually identical to the overreaching-transfer-trip system but contains provision for allowing short time (100 to 150 ms usually) tripping when the channel fails, provided a local overreaching distance relay operates. Trapping of the transmission line prevents “loss of channel” from occurring on external faults. Loss of channel not accompanied by operation of a distance relay merely sounds an alarm to indicate that condition.

Each of these schemes represent varying layers of complexity imposed on the basic concept of allowing one or more distance relays at each terminal to identify the existence of and the direction to a fault. Use of the pilot channel allows the two terminals to share this information and to initiate the appropriate action based on the comparison. While the description is in terms of 2-terminal

applications, they may in general be applied to the protection of 3-terminal lines. These systems incorporate subtle differences and small variations in their levels of security and dependability. They do differ in cost and capability, and their choice is greatly influenced by personal choice and individual previous experience.

Phase-Comparison Relaying. This form of pilot relaying compares, over a communication channel, the instantaneous direction of current at the two ends of the transmission line. To allow the use of a single channel, some such systems use a combination of the individual phase currents to generate a single-phase quantity for comparison. Others use a combination of the symmetrical components (positive, negative, and zero sequence) of the phase currents, and by applying appropriate weighting factors to each and adding the combination, a single-phase sinusoidal voltage is produced and converted to a square wave for comparison at the two terminals.

The concept of the scheme is that external faults will cause the local and received remote quantities to be essentially equal in magnitude but opposite in direction, while internal faults will cause them to be possibly different in magnitude but essentially in phase. In the comparison, the local quantity is delayed by an amount equal to the inherent channel delay, providing near-perfect coincidence for external faults.

The *segregated-phase-comparison* system compares the instantaneous direction of current at the two ends of the transmission line for each phase rather than utilizing some weighted combination of the currents or their symmetrical components. Modern high-speed channels allow information related to four subsystems (3 phases and ground) to be transmitted over a single voiceband in each direction. A local sinusoidal voltage proportional to phase current is converted, for each phase, to a square wave delayed by an amount dependent on channel delay and compared to the received remote quantity for the corresponding phase. Internal faults will produce essentially in-phase comparisons. External faults will produce comparisons essentially 180° out of phase. Considerable angular variation in these comparisons will still provide precise information regarding fault location. The ground comparison uses $3I_0$ current at the two ends of the transmission line.

Current Differential Relaying. To acquire the advantages of differential relaying for transmission lines similar to those obtained for generators and transformers, a scheme is in use that allows the waveform at each transmission-line terminal to be made available at the other. By using pilot wires, fiber optic, a microwave, or multiplexed digital channels the information is transmitted to the other terminal from which a phasor quantity is derived for comparison to the local quantity (delayed by the appropriate amount commensurate with channel time). This is accomplished using all the various technological forms: electromechanical, solid-state, and microprocessor. Excellent sensitivity and speed ($1\frac{1}{2}$ cycles) are achieved with this system and because of the abundant availability of digital communication channels, current differential applied to transmission lines becoming very popular.

Generator Relaying. Generators are a vital part of a power system, and their protection deserves is critical consideration. For the larger machines, 50,000 kW and above, a consistent pattern of protection has evolved. For the smaller machines, economics usually dictates that greater risks be accepted.

Large-Machine Protection

Hazards. The hazards against which protective devices guard are faults, unbalanced currents, loss of field, field ground, instability, and other miscellaneous phenomena that will be described later.

Phase Faults. Phase-fault protection is invariably provided by differential relays as shown in Fig. 16-10. By using identical ratio and accuracy-class current transformers, any “through” phenomenon such as load, external faults, or power swings will produce essentially equal restraint currents I_{R1} and I_{R2} . For external faults, operating current I_{OP} will be the difference of the two ct (current-transformer) error currents, or zero in the case of equal or negligible errors.

Internal faults generally will cause I_{R2} to reverse with respect to I_{R1} and I_{OP} to equal the transformed total fault current. The relays that are usually applied here have a sensitivity that is dependent on the restraint. For high through current, restraint is high, and the required I_{OP} is high, thereby restraining properly for possible high differences in error currents. For low internal fault current, restraint is much lower, and the I_{OP} required is much lower, allowing sensitive detection of the fault.

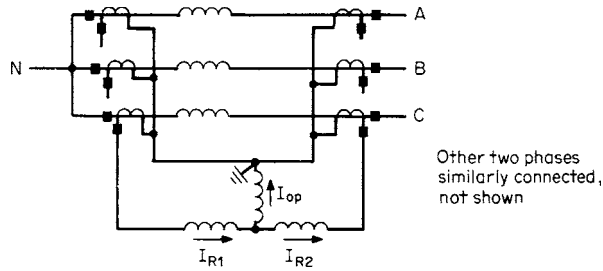


FIGURE 16-10 Typical differential protection for generator.

With this concept, large differential currents during external faults are ignored and the relay is sensitive for small differential current of internal faults.

Ground Faults. Stator faults involving conductor contact with grounded elements may cause essentially no current flow or current comparable to phase-fault levels, depending on the system neutral grounding. Most large machines are unit-connected, meaning the turbine, the generator, and the transformer are treated as a unit, with no fault switching at generator voltage level. The low-voltage winding of the unit transformer is delta-connected, providing zero-sequence isolation from all other segments of the power system. The generator neutral is grounded through a high-impedance circuit, usually a distribution transformer loaded with a secondary resistor. This combination limits ground-fault current to a few amperes, which is undetectable by the generator differential relay. With this widely used grounding method, the generator neutral shift is dependent on fault location. A ground fault at a generator terminal will cause full line-to-neutral voltage to exist between neutral and ground. The closer the fault to the neutral, the lower is the magnitude of this voltage.

A relay connected across the secondary terminals of the distribution transformer will be able to detect this voltage. It can be given sufficient sensitivity to detect faults from the line terminal down to approximately 4% of the neutral. It must ignore the normal third harmonic voltage, neutral to ground, to achieve this sensitivity.

The protection just described is blind to faults very close to the neutral point and consideration shall be given to complement with other relays or replace it with another principle. These schemes use the third harmonic voltage neutral to ground and sense its absence for a neutral-to-ground fault, or they interject a current at another frequency and supervise its level. Neutral-to-ground faults rarely occur and, in themselves, are of no consequence. A second ground fault not only will go undetected with neutral-to-ground fundamental-voltage-detection but also may destroy the generator.

Unbalanced Faults. Inherent in unbalanced faults is the fact that negative-sequence current is present. Flux associated with negative sequence rotates in a direction opposite to rotor rotation. This causes appreciable current flow in rotor structural parts that are not designed for such current, and excessive heating occurs. A relay designed to respond in a similar way to the machine is applied for this protective function. It is $I_2^2 t$ responsive, where I_2 is per-unit negative-sequence current (on the machine full-load current base) and t is time in seconds. Generators vary in capability from $I_2^2 t$ of 5 to 40 for negative-sequence currents in excess of full load, depending on the type and size of machine.

The negative-sequence current relay protects the generator against a prolonged contribution to an unbalanced fault beyond the generator breaker. It often contains provision for “alarming” at a lower level than the tripping level to annunciate the hazard of a sustained unbalanced current condition.

Loss of Field. Field failure caused by any event, such as loss of regulator, opening of field breaker, field short, or field open, will cause a large var flow into the machine and generally a substantial reduction in terminal voltage. This may or may not seriously jeopardize the machine, or it may jeopardize the stability of other adjacent machines. It requires detection and removal of the machine from the system.

Most loss-of-field devices utilize generator terminal voltage and phase current to obtain impedance and phase angle. Loss of field causes impedance at the relay to decrease and current to lead more. This

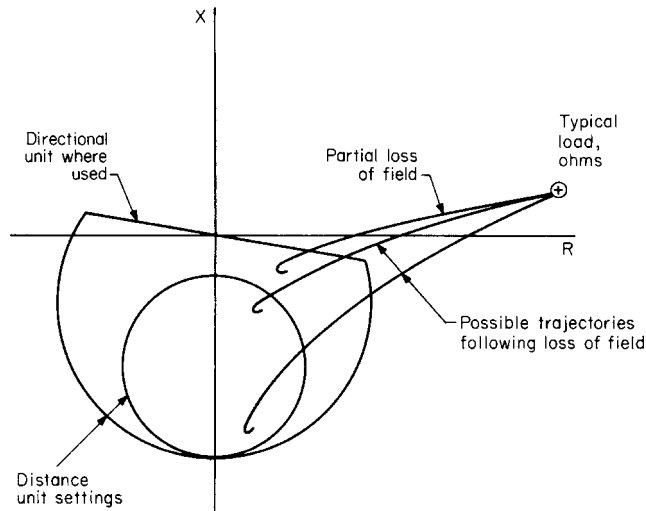


FIGURE 16-11 Detection of generator loss of field by measurement of impedance.

phenomenon is usually detected by “distance” relays as shown in Fig. 16-11. Apparent ohms as viewed from the machine terminals enter the characteristic circle of the relay, causing it to operate.

All such relays are equipped with time delay to avoid undesired tripping on power swings. Some contain directional and undervoltage units to permit additional sensitivity to partial loss of field and allow coordination with regulator minimum excitation units, the machine capability curve, and the steady-state stability curve.

Field Ground. A single field ground causes no machine distress. Allowed to go uncorrected until a second field ground occurs, it can cause sufficient magnetic unbalance to produce *catastrophic* vibration. For “brush-type” machines, detection of the first ground is usually accomplished by detecting current flow in a high-impedance dc-measuring circuit to ground. AC is also used in other devices through the introduction of an ac voltage between the dc field circuit and ground and monitoring the low-magnitude normal current that is allowed to flow.

Where a “brushless” arrangement is used, no normal access exists to the field circuit because there are no nonrotating parts at field voltage level as there are in brush-type machines. Monitoring for grounds is achieved by periodically dropping, manually or automatically, pilot brushes onto collector rings provided for the purpose. One collector is connected to the neutral of the 3-phase ac exciter, and the other is connected to the rotor structure itself. Measurement of the voltage between these two points with an overvoltage relay allows detection of a ground fault at any point in the field circuit.

Instability. When the electrical center appears to be in the transmission system, distance relays applied to protect the transmission lines can be used to detect instability and to separate the two system parts. This usually can be done discriminately with out-of-step blocking at some locations and tripping at others, all done in the interests of maintaining as nearly as possible a generation-load match after the separation.

On the other hand, when the electrical center falls in the unit transformer or in the machine, the normal complement of relays applied to generator or transformer protection either will not detect the out-of-step condition or will be time delayed to the point of being unreliable for this function. In these cases, out-of-step relaying is applied.

Figure 16-12 demonstrates the system behavior for a fault condition and for an out-of-step condition as viewed from the machine terminals and plotted in terms of a resistance-reactance diagram. Advantage is taken of the fact that emergence from the area between the blinder lines is on the same

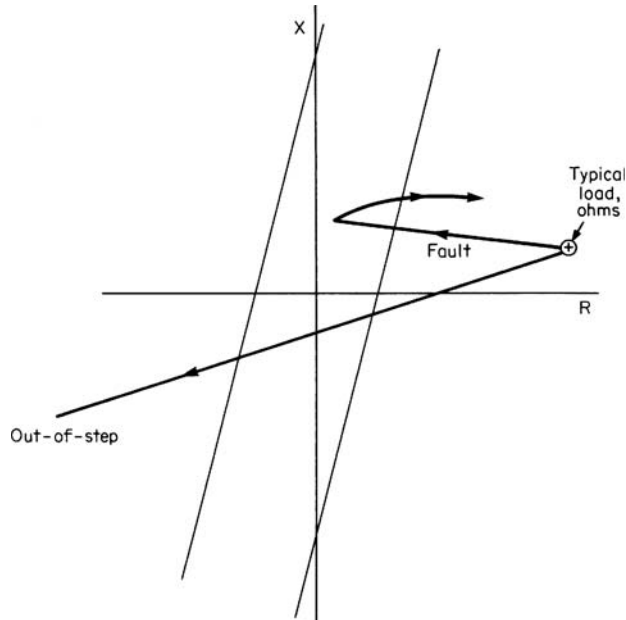


FIGURE 16-12 Blinder scheme for generator out-of-step detection.

side as entry for normal fault clearing and on the opposite side from entry for an out-of-step condition. A blinder-type out-of-step relay trips for the latter case.

Other Protection. For large, important units, relaying is included to detect motoring of the generator, inadvertent energization when the machine is at standstill, excessive volts per hertz that in turn causes excessive transformer and generator iron heating, stator and field overcurrent, and any malfunction not detected by the first line relaying (i.e., backup must be included to prevent catastrophic failure in the event of protective device malfunction).

Small-Machine Protection. Much individual preference goes into the choice of protective equipment for small machines. For the very small, only voltage-restrained or supervised overcurrent relays may be used. In some cases only over- or undervoltage and frequency detection is applied. In other cases, protection approaching that for larger machines is used.

In some cases, compromises with the more elaborate protection are used. For very small machines, time-delayed overcurrent relays with insensitive settings are used in the differential configuration. Specially connected watt relays are used for a combination loss-of-field and out-of-step detection function. Modern microprocessor packages contain most or all of the relaying functions necessary for generator protection plus monitoring, fault recording, and oscillography. They provide very low burden, self-checking, and greatly reduced panel-space requirements.

Motor Protection. Both synchronous and induction motors have protective requirements similar to those of generators. One important difference is that motors are accelerated by applying full or reduced voltage to their terminals, while generators are brought up to speed by their prime mover before being connected to the power system. Large starting current, then, is a normal expected phenomenon associated with motors that generators do not experience. Both types of devices contribute to external phase faults. Motor neutrals are not generally grounded, so no ground current will flow in an unfaulted motor.

Any protective device applied to protect a motor must ignore the conditions of starting current, load, and “through-fault” current, at the same time being able to sense low-magnitude internal-fault current. Differential relays perform this function well, often using a through-type current transformer with the two leads associated with each phase physically inserted through the ct window. Equal in-and-out currents generate no secondary voltage, so no operation of the relay connected to the ct secondary occurs. Internal faults cause unequal currents which generate a secondary voltage to cause instantaneous relay tripping. For larger motors, differential relaying schemes identical to those used for generators are used for phase-fault detection.

A ground-relaying variation of the “through-type ct” scheme requires that all 3-phase conductors be inserted through the ct window. Only ground faults on the motor side of the ct can cause the relay to operate. This is a widely used scheme. Another important element for detecting a fault in a motor is an instantaneous-trip phase device. It must, of course, be set above motor starting current, but available phase-fault current magnitude usually will greatly exceed the starting current magnitude, and very effective use can be made of this inexpensive and simple device.

Thermal Protection. Motors are usually equipped with devices that detect and relieve motor overloading. These are either devices that experience a heating effect comparable with that of the motor itself and act accordingly or are relays that detect the temperature of a resistance-temperature detector (RTD) (through a measurement of its resistance) embedded between conductors in the stator slot. As the motor temperature increases beyond the allowable level, the RTD resistance rises, and tripping of the controller takes place. Modern digital relays provide sophisticated models for the thermal behavior of the motor that operates when the thermal capability is violated.

Locked-Rotor Protection. Neither of the relays used for thermal protection will, in general, protect a motor with a locked rotor. A time overcurrent relay receiving one phase current will normally perform this locked-rotor protective function adequately. In some special large-motor applications where permissible locked-rotor time is less than the required starting time, distance relays have been used successfully to run timers to protect for the locked-rotor condition based on a measurement of a combination of motor impedance and phase angle.

Unbalance Protection. Any degree of voltage unbalance at the motor terminals will manifest itself in the form of increased heating in the motor, well beyond that which could be predicted from the increase in stator current. This can be sensed by a relay which measures voltage unbalance or negative-sequence voltage. Buses that supply a large number of motors are usually equipped with this kind of protection. Phase-current magnitude comparison also has been used very successfully on circuits supplying a single large motor.

Synchronous-Motor Protection. Because of the unique characteristics of synchronous motors, they are usually equipped with loss-of-field and out-of-step protection. This is often provided by a relay responsive to volt-amperes at an angle representative of the var flow into the motor on loss of field. It also will respond on loss of synchronism if the rate of pole slippage is compatible with the relay operating time or if the relay has a delayed resetting characteristic.

Transformer Relaying. Protection of large transformers generally consists of differential protection, gas space or oil rate-of-rise of pressure, or gas accumulation detection plus time overcurrent relays for backup.

Differential Relaying. The differential-relaying concept is applicable to transformer protection in a manner similar to that for generator protection, but distinct differences exist. While current transformers having essentially identical ratios and characteristics are obtainable in generator protection, no such identity is possible with the ct's used in transformer protection. Inherently, they *must* have different ratios and probably will have quite different characteristics. Also, inrush current on initial energization and following external fault removal is a very real phenomenon that must be accommodated by the transformer differential relay. These two circumstances, different ct's and inrush, makes the transformer differential relay different from the one described for the generator.

In addition to the fact that “through” conditions such as load or external faults produce different currents on the two sides of the transformer (to cause equal ampere turns in the windings), for a wye-delta

or delta-wye transformer there is also a phase shift between the line currents on the two sides. Further, the standard ratios of ct's (such as 1200:5, 600:5, 100:5) used on the two sides of the transformer do not generally produce equal secondary currents for comparison by the differential relays for through conditions. As a result of these considerations:

1. Delta-side ct's are connected in wye.
2. Wye-side ct's are connected in delta.
3. Balance of input currents in the ratio of as much as 3:1 may be done inside the relay.
4. Inrush current is distinguished from internal-fault current in most transformer differential relays by using all harmonics, a combination of harmonics, or second harmonic only for inrush restraint.
5. Restraint is produced in proportion to the magnitude of the through current causing the relay to be sensitive at low current where ct error is likely to be low and to be insensitive at high current where ct error will be higher.

Microprocessor relays are able to perform these functions, previously assigned to electro-mechanical and solid-state relays. They allow all the current transformers to be connected in wye, irrespective of the protected transformer connection, through the use of an algorithm that supplies the appropriate phase shifting. This permits retention of phase designations for the monitoring and oscillographic display.

A widely used scheme for protecting a wye winding of a transformer against ground faults is shown in Fig. 16-13. The auxiliary transformer is carefully chosen with a ratio that will minimize the effect of ct error for external faults and force a restraint condition (currents not flowing into the winding polarity markers simultaneously) to exist. Internal faults produce a reversal in the operating current direction with respect to the polarizing (reference) current direction causing the relay to operate. Another common application uses a time over-current relay supplied by a neutral ct connected in a wye-winding ground connection. It must be time-coordinated with other ground relays on the power system connected to the wye winding. Where differential relays are used, the primary function of this neutral ground relay is to back up these other devices.

A neutral-ground relay may accomplish a primary (or first-line) relaying function where low-resistance grounding is used and high-voltage fuses are used. The typical fuse size required for full-load capability will not detect a low-voltage winding failure to ground in such a case. The ground relay will, depending on fault-current level. Remote tripping of a breaker feeding the fused transformer will be required. Tripping of a low-voltage breaker will not clear this type of fault.

Rate of Rise of Pressure or Gas Accumulation. Depending on whether a transformer is designed to have a nitrogen space above oil or to have a "conservator tank" and be completely filled with oil, use will be made of a rate of rise of gas pressure or a rate of rise of oil pressure device in larger transformers. Normal load cycling causes pressure change, but the rate of change is moderate. Faults under oil cause a much higher rate of change, and this distinction allows this type of device to distinguish between load change and faults. Gas-accumulation relays collect any gas generated under oil by arcing or excessive temperature and base their fault detection on the extent of this collection.

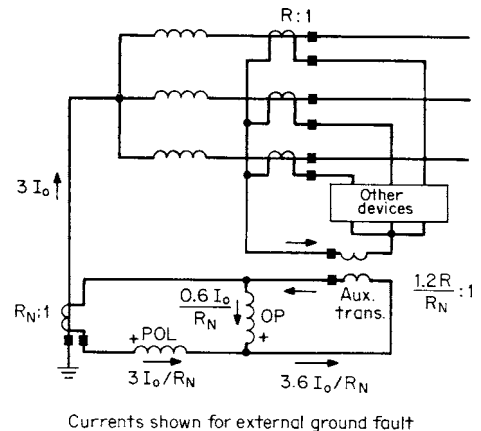


FIGURE 16-13 Transformer wye-winding differential protection.

16.3 POWER-SYSTEM COMMUNICATIONS

BY GEORGE R. STOLL

16.3.1 Introduction

Power-system communications play a vital role in the safe and efficient operation of the electric power grid. Real-time automation and control of electric utility generation, transmission and distribution systems are dependent upon reliable and secure communication networks. Through an ever-expanding role, the communications' networks enable the application of more computer and microprocessor-controlled devices. These networks and devices support the better utilization of extensive EMS and corporate information technology infrastructure. In addition, they enable the provision of new energy-related services and enhance the reliability and the safety of personnel and equipment.

Power-system communications application typically support various elements of a power utility's control, planning, accounting, and administrative functions. With deregulation of the U.S. electric utility environment, additional functions, including the marketing of bulk electric energy and transmission line access is also required.

This section will primarily address communication functions and the systems they support for power-system *operations*. The operation functions have certain communication requirements that are unique to the electric utility industry. Many of the other utility telecommunication functions, such as administrative voice and data, have communication requirements similar to those of other large business enterprises.

16.3.2 Communications/Control Hierarchy

Most power systems are vertically integrated; they perform the functions of generation, transmission and distribution, typically owned by the same entity. With deregulation, this model is in transition and ownership, and operations responsibilities vary with the country, the type of ownership and the size of the utility. In the United States today, the power marketing function (including the scheduling of generation, sale of bulk energy and transmission line capacity) has been separated from the transmission grid operations. This is to allow for an independent, nonbiased marketing of energy and transmission line capacity in a competitive market place. Previously, these functions were integrated into the same dispatch and operations center and frequently performed by the same personnel.

While deregulation is changing the way many companies are organized and requiring more communications infrastructure, the basic communications functions between the various control centers, generating facilities, transmission, and distribution elements are fundamentally similar. Figure 16-14 is a simplified overview of the current U.S. model, illustrating the relationship between major power-system elements along with their communication requirements.

16.3.3 Utility Communications Network Design Considerations

Most private utility optical and microwave wide area networks use time division multiplex (TDM) as the means for allocating a portion of a network's bandwidth to an individual circuit. By implementing a high sampling rate for each individual circuit, a very high quality, low delay (also termed *low latency*) channel can be transported over the private network. This high-quality and low-latency circuit format is well suited to the mission critical and oftentimes sensitive circuit requirements of an electric utility. And, this is not unlike the common carrier and public network cable, wireless and optical transport schemes used until recently.

With the advent of the Internet and associated technologies, wide acceptance of a form of packet-switching protocol, termed Internet Protocol (IP), is starting to become widely used in wide area, public communication networks. Unlike TDM circuits, a packet circuit is not continuously connected. The packet circuit divides the information to be sent into packets, and each packet may take a different route through the network (or series of networks) to reach its destination. At the destination,

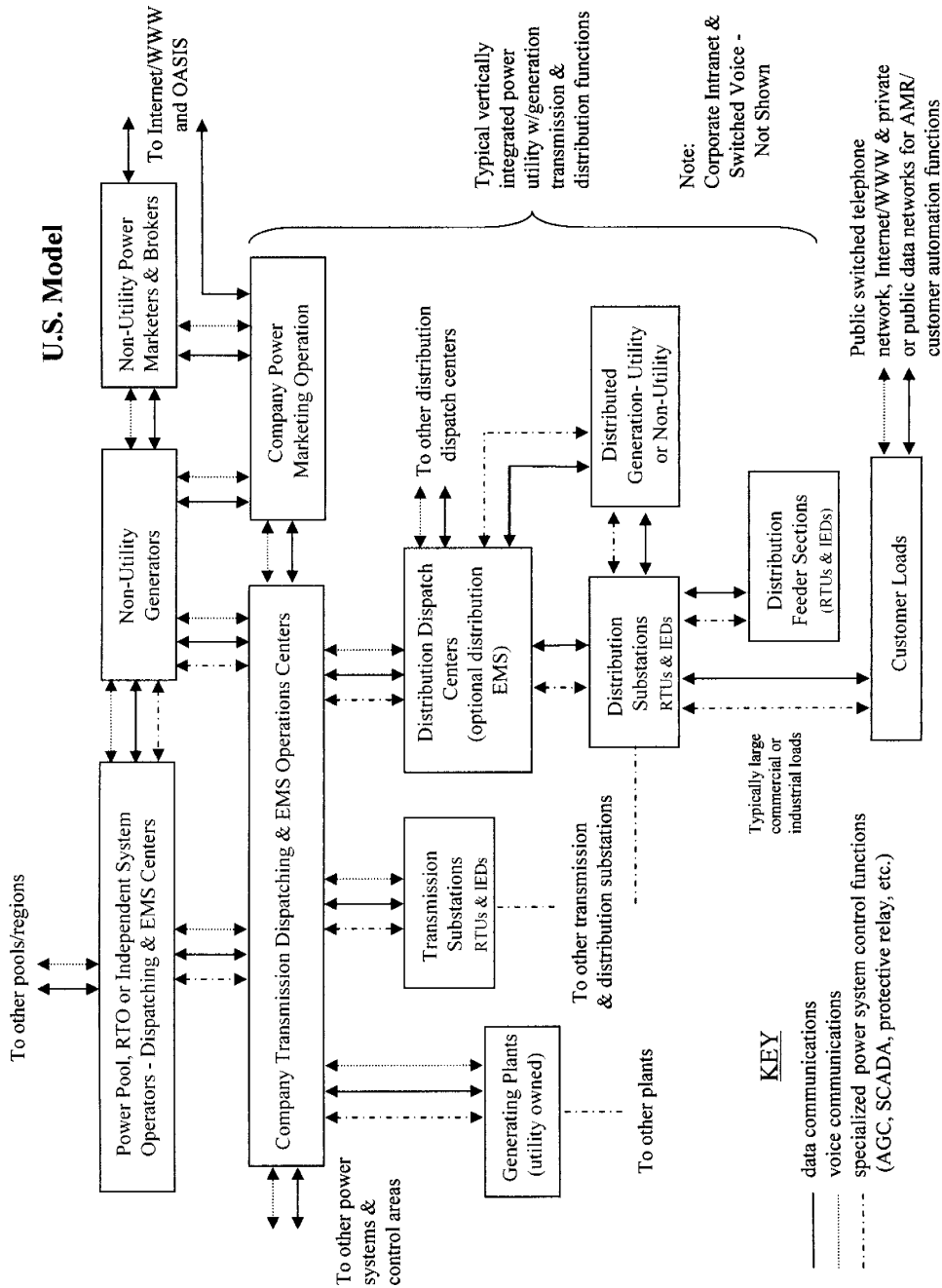


FIGURE 16-14 Interconnected power-systems—telecommunications requirements U. S. model.

the packets are assembled into a sequence matching the information originally transmitted. When no information is being transmitted, no network resources are utilized. This feature allows other users of the network to use its capability, or share the resource and thus increase its efficiency when used for less time critical data transmissions.

However, the disassembly, transmission time and reassembly of packets of information over IP networks add latency to all information being transmitted. Depending on the quality and capacity of the IP network and other technical factors, the information transmitted may be delayed anywhere from tens of milliseconds to several seconds. While acceptable for many types of data and even voice, these delays are not acceptable for many types of power-system operation channels.

This does not mean that IP cannot be used to implement operations circuits. With the use of significant additional bandwidth, IP formats can be transported with the latency and constant delay required. With excessive bandwidth, TDM circuits can be emulated over IP. However, this is typically only implemented over optical fiber networks where the utility manages the network. Because of the low cost of IP equipment and the availability of private utility company fiber networks with much more bandwidth than microwave, more IP networks for utility communication systems will be implemented in the future.

16.3.4 Specialized Power System Communications

In addition to the voice and data network communications typical in many multifacility industrial or business complexes, there are communication requirements unique to the electric power industry. These include:

- Protective relay
 - Transmission line protection
 - High-voltage switching equipment protection
 - Generator and transformer protection
- Telemetry and telecontrol
 - Analog and digital telemetry
 - SCADA
 - Remote alarms
 - AGC
 - Remote metering—real-time metering—revenue metering
- Voice communications
 - Dedicated dispatch phones
 - Two-way radio dispatch
- Other data communication links
 - Computer to computer links
 - Open access same time information system (OASIS) and the Internet
 - Regional transmission organizations

16.3.5 Protective Relay Communication Channel Requirements

Protective relaying is unique in that the communications channel is faced with very stringent security and reliability requirements. Security requires that the communication channel never cause a false trip output. Reliability requires that the channel always be in service and function when needed. This requirement must be met even as the communication equipment is subjected to the harsh electronic environment present at substations, switchyards, and generating plants. Protective relay equipment must operate during and after a fault condition and in the presence of electrical noise, ground potential rise, and transient voltages common to these environments.

In addition, the communication channel must not add excessive time delay to the overall protective relaying function. Where the electrical circuit breaker is located at a remote location from the sensing relays, the channel is usually allocated up to 16 ms (about the time required for one

cycle of the power-system frequency) total transit time. Extensive industry experience led the U.S. North American Electric Reliability Council to issue typical protective relay communication channel timing and redundancy requirements. Most protection schemes require communication channel times less than 16 ms. An exception to this is blocking schemes; requiring channel times less than 4 ms.¹

Typical analog communication channel transit times range from 10 to 16 ms. These speeds are attained with direct links between the substations and usually via microwave or fiber communication systems. This is a function of the distance between the terminals, modulation methods, and the medium. An all-digital communication system can be faster than older analog transmission methods because there are no voice-frequency filters and baseband conversions, which add delays. However, in digital systems, application of digital access and cross connect functions or higher-order multiplexers can add unacceptable protective relay channel delays. Without the higher-order multiplexing and switching, one digital microwave equipment manufacturer reported a total channel transit time of 5.3 ms for a 640-km, all-digital microwave protective relay channel.² This channel transit time is inclusive of the transmitter time, the propagation time for the signal to travel to the remote end, the receiver detection time, and the operating time of the communications output device.

A majority of the total time required to clear a fault is a function of the breaker's operating time and the protective relay's detection time. These are those characteristics that cannot be readily changed. The communications channel is often the only variable element in the total timing required to detect and clear remote faults on the power system. With higher transmission line voltages, the longer the fault clearing time, the greater the potential damage to the utility's electrical equipment. Thus, the justification for the emphasis on protective relay communications channel speed.

16.3.6 Telemetry and Telecontrol

Telemeter and telecontrol signals provide information to the operators and may also serve as computer system input signals. Telemetry permits remote measurement of current, voltage, real and reactive power, position, flow, and other data relevant to operation of the power system.

Digital systems typically have an RS-232, RS-485, or an Ethernet interface to the communications media. Older analog systems typically use a transducer to convert the parameter being measured to a dc voltage or current. Telemetry equipment at the remote location linearly converts the dc voltage or current from the transducers to a sub-audible frequency, usually in the range of 10 to 30 Hz. This subaudible frequency is used to modulate frequency shift tone transmitters with an output in the range of 420 to 3300 Hz or higher. These signals can be transmitted over standard voice-grade communication channels carried on telephone, microwave, or optical fiber links. At the receiving end, tone receivers convert the audible frequencies back to voltages or currents (typically 0 to 100 mV or 0 to 20 mA), which in turn are used as inputs to monitoring, recording, control, or computing equipment.

With the emergence of sophisticated SCADA systems, a great deal of analog telemetry is being replaced with full digital systems or integrated into the SCADA system. The SCADA systems are designed to provide telemetry and control functions of multiple points (or subsystems) within a station. The SCADA's computer and electronics located at the remote location (such as a substation) are termed RTUs. The RTUs communicate with a master located at the dispatch or EMS center. Master and remote units communicate with each other using a series of digital messages that convey the addressing, control or status information and error checking. This communication can take place over a voice grade communication channel or via an all-digital communication link.

Supervisory control and data acquisition communication between RTUs and the master take place with one of three access sequences. These basic access methods include a polling format, a scheduled or a contention access.

Polling Access. The master periodically sends a request for information/control command sequence to the RTU.

Scheduled Access. The RTU initiates communications to the master on a predetermined schedule.

Contention Access. The RTU or the master may initiate a communications process whenever a control command needs to be transmitted or a status changes. The communications process includes the intelligence to perform data transmission collision avoidance, detection, and retransmission functions.

Combinations of these access methods is also common. In one variation, an RTU may not communicate with a master station unless a control status or data value has changed, termed *report by exception*. In other variations, certain critical events at the substation may trigger a normally polled RTU's immediate communication with its master station. Rather than wait for its assigned time slot in a polled sequence, it communicates virtually instantaneously with its master.

RTUs and Microprocessor Technology. The role of the RTU in the electric power substation is changing. The advent of intelligent electronic devices (IEDs) and programmable logic controllers (PLC) means more devices, such as protective relays, have electronic intelligence and the ability to be dynamically controlled and monitored. Rather than provide a dedicated communications channel to each IED or PLC, these devices may communicate with the local RTU. The RTU, in addition to its primary data collection and control function, acts as a data concentrator and protocol converter. It is becoming common place to see the IEDs and controlled devices networked together within a substation via a local area network (LAN).

16.3.7 Automatic Generation Control

Automatic generation control provides the telemetry and telecontrol to support tie-line and load-frequency control functions. These systems scan (sample) the individual unit generation and tie-line power flows. Via centralized computer control, they generate the raise/lower control pulses sent to individual electric generators. These systems can be very time-critical, but usually do not have as stringent a communications channel requirement as protective relaying. Formerly all analog and using dedicated channels, many of these systems today are now digital or incorporated into the EMS functions.

16.3.8 Voice Communications

Voice communication with and between field personnel and the various dispatch, power pool, and EMS centers takes place over telephone and radio systems. In addition to use of the public switched telephone networks, power systems frequently include dedicated circuits between the dispatch and control centers. Often these are configured so that minimal or no dialing is required. The circuit may be transported over private or dedicated networks. These are termed *hotline* or *ringdown circuits*. They allow dispatchers to communicate with each other without the normal 10- to 20-s delay caused by dialing and the public network's switching, routing, and signaling functions.

Two-way radio communications are used for communications with field personnel performing operations, maintenance, and electric service restoration. These systems operate in the very high frequency (VHF) 30 to 300 MHz or ultra high frequency (UHF) 300 to 1000 MHz portions of the radio spectrum. Larger utilities may use trunked radio systems, where multiple radio channels and their use is computer controlled. In a trunked radio system, the channels are dynamically assigned as needed, allowing efficient use of the radio spectrum. Smaller radio systems use conventional, dedicated radio channels. These are analogous to a "party line" environment, where all the users on the channel can hear each other. In these configurations, an individual radio channel may be shared by the various functions within the utility.

Large dispatch and energy control centers have radio dispatch consoles. These consoles consolidate all the radio system control functions, allowing the system operators to quickly access the mobile radio systems and to communicate with field personnel throughout their service territory. These radio consoles may be stand-alone units or have voice telephone functions integrated into them.

16.3.9 Other Data Communication Links

Bulk data information exchange takes place between the various power-system's computers. Data traffic over these links may include the EMS system's generation scheduling, fuel cost and generator availability, transmission capacity, load predictions, interchange billing, frequently weather information, and other data relevant to power-system operation. These data links are usually over dedicated communication channels and vary in data speeds from a single DS-0 (64 kbits/s) to T1 or E1 rates.

Oasis and the Internet. In the United States, the Federal Energy Regulatory Commission (FERC) established requirements for implementing open access to the electric transmission grid.³ Ultimately, this open access to electric transmission lines will allow almost any generator of electric energy to sell to any purchaser. Implementation requires additional communications, establishment of wholesale power marketers and independent system operators who act independently of the utility that owns the transmission lines and/or generates the electric energy. To address how transmission line capacity and availability information would be made available to everyone at the same time, on a uniform basis, FERC defined an application of the Internet.⁴ All entities that generate electricity for the open market, own electric transmission lines, or buy energy from these parties will need to use the Internet to exchange information. Termed OASIS, these Internet based, specialized information services allow anyone with access to the Internet to view the capacity, availability, and associated costs of electric power and its transmission. OASIS is currently serving as a shared database of information. It may develop into an intelligent system capable of performing generation scheduling, and control.

FERC Order 2000. Following implementation of the transmission line open access rules, FERC released an order requiring all the U.S. high-voltage transmission line owners to tell FERC how they would organize regional transmission organizations (RTOs)⁵. Regional transmission organizations are intended to be a consolidation of independent system operators (ISOs). The objective was to lower the number of ISOs and simplify the communications and marketing communications. Today, there are both RTOs and ISOs and the exact definition of the bulk transmission and generation model is still evolving. From a communications perspective, all variations of these power system models require additional voice and computer communication links along with more real-time data of power grid operations.

16.3.10 Communication Alternatives

As communication alternatives are considered for power-system operations, factors including circuit capacity, reliability, latency, jitter, and other technical parameters along with cost must be considered. Many organizations categorize their circuit requirements into *level of service* categories. Levels of power system telecommunication service can be grouped into three general categories.

System Critical. These are communication links that are extremely reliable and which support process and control functions requiring near real-time communications. Communication paths are available full time, they are usually dedicated to specific functions and the process or control function they support is usually computer controlled and has total response times ranging from milliseconds up to several seconds. Examples of system critical power-system communication links include protective relay channels, LFC, AGC, tie-line control, many SCADA systems, and some computer links.

System Priority. These are communication links that support voice and data functions with total response and control times ranging from several tens of seconds up to 1 h. Communication links may be dedicated or shared and provided by the power utility or a public carrier. The process or function supported may require or allow human intervention. The communication channels are usually very reliable and seldom blocked, or not available. Examples of system priority communication links include voice dispatch circuits, the voice two-way radio systems, computer-to-computer data links, and local and wide area data networks. They also include commercial and industrial electric load

shedding, metering of large commercial and industrial loads, less time-sensitive SCADA functions, and distribution and feeder network automation systems.

System Administration and Support. These are communication links that support power-system functions where near real-time or very time-sensitive communications are not required. Channels support functions or processes with acceptable response and control exchanges ranging from minutes to days. If a communication exchange is interrupted or lost, it can be resent without severe implications to the safe and efficient operation of the electric power system. This category includes all types of administrative voice and data via the public-switched networks, private branch exchange systems and metering, planning, scheduling, billing, and customer service communications. In the U.S. model, it also includes use of the Internet for many of the transmission access scheduling and power-system marketing functions.

The level of service, process response times and media/provider selection criteria for typical power-system communications functions are represented in Fig. 16-15.

16.3.11 Communications Media/Service Type

Power-system communication networks are typically composed of systems using several technologies and, often, multiple service providers. Following are some of the most popular types of systems and services used to support the specialized needs of the power utility.

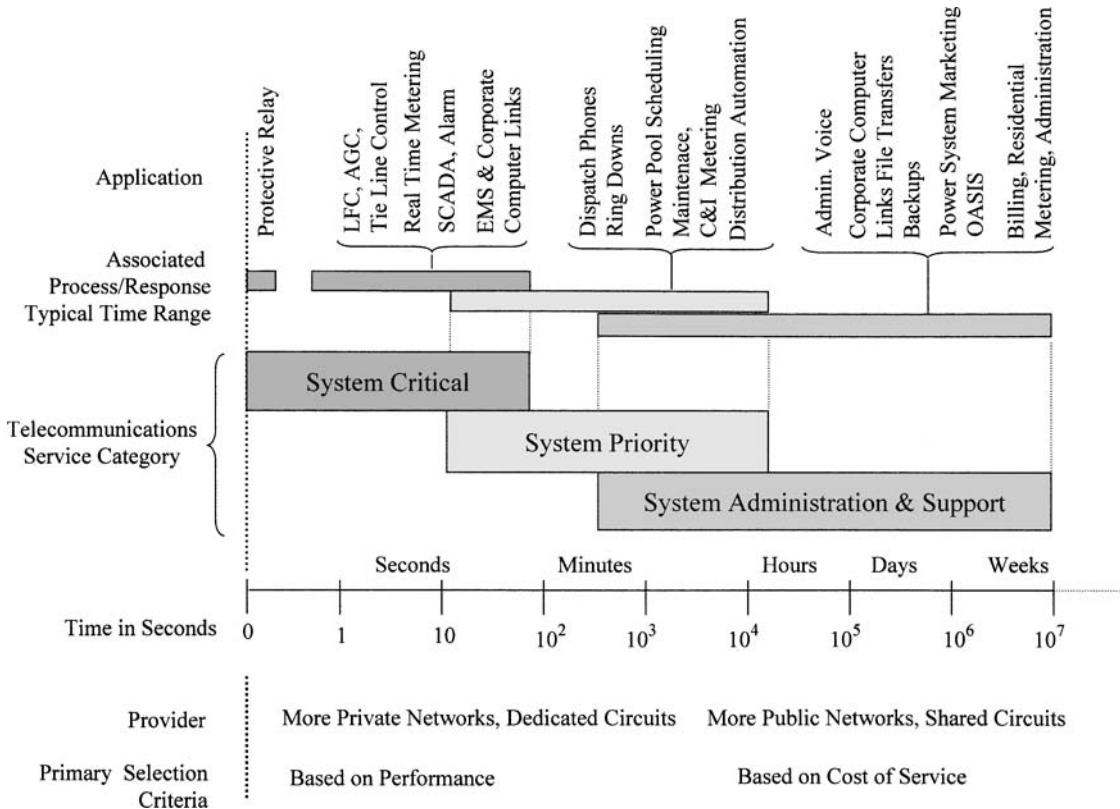


FIGURE 16-15 Power-system communications—application vs. service category.

16.3.12 Private Point-to-Point Microwave Systems

Private microwave systems have proven to be a very reliable and cost-effective method of supporting a wide range of communications needed for power-system operations. These systems operate in assigned frequencies ranging from 2 to 23 GHz. Very reliable links can be established for distances up to 80 km each, depending on the intervening terrain, the operating frequency and the height of the antenna systems. Multiple stations (repeaters) can be “chained” together for end-to-end system distances of thousands of kilometers. Most systems require licenses, although some spread spectrum systems with limited capacity and range are available for short-haul services.

A drawback to microwave systems is their requirement for a line-of-sight path between stations, often requiring large towers to support the antenna systems (Fig. 16-16). Spectrum may not be available



FIGURE 16-16 Microwave systems require large towers for line-of-sight paths between stations.

due to heavy use of the limited amount of assigned frequencies. Systems operating at 10 GHz and higher are more sensitive to rain and atmospheric conditions, resulting in shorter path lengths.

Digital point-to-point microwave systems can be designed to provide very high reliability with error rates of 10^{-9} or better. They also can be configured to provide minimum channel delay, so they are ideally suited for protective relay channel service. Once microwave systems are installed to provide required power-operations communications, it can be cost effective to use them also to transport the power system's administrative voice circuits and other corporate communications.

16.3.13 Leased Telephone Circuits

Telephone circuits, both dedicated, direct point-to-point, and the switched lines that are transported through the public telephone networks are widely used for power-system operations. They can be cost-effective for the system priority and system administration and support category functions that do not have extremely demanding availability, reliability, and error rate requirements. Switched circuits, also termed dial-up circuits, can be ordered and installed quickly in most populated areas. Error rates vary over a wide range and are a function of the quality of the local telephone company's cable plant and distances to central office equipment. Another concern with leased telephone circuits is that they are often transported by multiple carriers, making it difficult to identify intermittent problems.

Voice grade, dial-up circuits may be able to transport data rates to near 56 Kbps in metropolitan areas that are close to the telephone company's central offices. Rural environments can expect much lower data rates. Digital leased circuits are available in some areas that will transport data rates to DS-3 (45 mbit/s) or higher with good error rates, but these can be costly.

A majority of leased telephone circuits use a metallic conductor in some portion of the circuit, usually in the last mile segment where they enter and exit the power company facility. Their metallic conductor and cable sheath make them susceptible to induced noise and voltages (magnetic induction) and ground potential rise that are common in power-system environments. With ground potential rise, a local fault may cause the voltage potential of the electric station ground grid to rise to several thousands of volts, while the telephone company's central office ground remains at zero potential. This difference in ground voltage appears as a high-voltage on the utilities equipment connected to the telephone circuit. This cannot only damage equipment and the cable, but also presents a safety hazard to personnel working on the electronic equipment.

To protect the connected equipment and personnel in near proximity to these metallic cables, transmission substations typically require sophisticated telephone line protection devices. These are required to eliminate the harmful voltages that would otherwise be present on the telephone cables and the cable sheath. These devices may take the form of short fiber-optic links (with the fiber and all interface electronics mounted in a dielectric cabinet), isolating transformer or neutralizing transformer installations. The fiber-optic devices are generally replacing the neutralizing and isolating transformer installations because they do not require as careful a design or remote grounding considerations.

16.3.14 Satellite Services

Most traditional communication satellite systems use a single satellite placed in a geostationary orbit, 36,000 km above the earth's equator, functioning as a microwave signal repeater. Several newer systems use multiple satellites in lower orbits categorized as low-earth-orbit (LEO) and medium-earth-orbit (MEO) systems. Power-system operations have made only limited use of satellite technology.

Traditional satellite systems can transmit large amounts of digital information, in the form of voice or data, with low error rates. However, a characteristic of all geostationary satellites that eliminates them for most power-system-critical communications is the propagation time associated with the microwave signal. Transmitting the signal 36,000 km from the earth to the satellite and back again adds approximately 250 ms to the communication channel time. Many systems use a double-hop technology, where all signals are relayed through a large earth station, boosting the signal and thus allowing for the application of small parabolic antennas at remote stations (termed *very small*

aperture terminals, or VSATs). This doubles the delay, yielding an overall channel propagation time of nearly 1/2 second. Add to this the access and back haul times, error correction and overhead, and round-trip times can be in the order of 2 to 3 seconds. This delay creates problems for the polling and response timing in many EMS systems and causes geostationary satellite technology to be totally unacceptable for protective relaying.

Other Satellite Services. Low-earth-orbit (under 2000 km from the Earth's surface) and medium-earth-orbit (10,000 km) systems are in service and are used in a limited manner for power operations that are not time critical (certain types of remote metering). These multiple satellite systems offer voice and data, usually on a worldwide basis. Low-earth-orbit systems are being used that can offer meter reading and some types of SCADA services. Because these systems are closer to the earth's surface, there is a considerable improvement in transmission delay times versus geostationary satellite systems. Primarily using packet data formats, there are still time delay issues.

16.3.15 Private and Commercial Land Mobile Radio Systems

Land mobile radio systems are widely used to support power-system field operations. They operate in the VHF region (30 to 300 MHz) or the lower portion of the UHF region (300 to 900 MHz). They primarily support voice operations over narrow bandwidth channels. Some systems also support limited mobile data and status messaging. However, with data rates over this bandwidth limited radio channel typically below 9600 bits/s, only a minimum amount of data and status information can reasonably be transmitted.

Many utilities have private systems (owned and operated by the utility) although a wide variety of commercial services are available. These systems use conventional (half or full duplex) communications over individual dedicated radio channels or for large systems, trunked access over multiple channels.

Commercial systems typically use more trunking and spectrum efficient systems and often cover wider service areas. They are seldom used for power-system dispatch operations because of concerns over reliability and channel access during busy periods or regional disasters.

Limitations of land mobile systems include the limited availability of additional spectrum, congestion on existing channels, and the requirement of an often complex licensing process. Radio propagation at UHF frequencies limits the system range to near line-of-site distances with somewhat greater distances for VHF. Installation of a wide area system requires locating the transmitting equipment on tall towers, buildings, or mountaintops.

16.3.16 Cellular and PCS Wireless Services

Cellular radio service (operating in the 800 to 900 MHz spectrum) and personal communications services (PCS) (operating in the 1.9 to 2 GHz spectrum) are used by power-system operations for the *system administration and support* category of mobile voice or low priority, low data rate (typically under 56 kbits/s) mobile data communications.

Cellular and PCS systems provide service in metropolitan and many rural areas. Low power mobile or handheld transceivers communicate with nearby radio base stations configured in a cellular pattern. The base stations (termed cell sites) are linked with each other and the public telephone network. The system is designed so that the base stations can reuse the radio channels of other nearby cells, thus allowing many subscribers to simultaneously use the spectrum.

Their circuits often do not meet the quality or reliability criteria needed for higher priority power-system operations. Serving as wireless telephones and frequently as low speed data transceivers, they are not designed with the same grade of service as the U.S. wire-line public telephone network. During busy periods, calls can be blocked from accessing the cellular network and calls in progress may experience interference or may be terminated.

In addition to the popular mobile voice communications, cellular service is also widely used in power-system operations to support low priority, occasional dial-up or unsolicited alarms from remote locations where more expensive, higher reliability EMS systems are not justified.

16.3.17 VHF and UHF Radio Data Links

Very high-frequency and UHF radio systems are frequently used to support EMS and telemetry links. These data-only systems can be configured as point-to-point circuits (typically in the VHF frequency region) or as point to multipoint (the UHF frequencies). Point-to-multipoint systems are also termed multiple address systems. Characteristics of most of these systems include data rates in the 2400 to 9600 bits/s range, but actual throughput is much lower than this, since most systems use a shared channel or some form of polling access. System error rates can be as high as 10^{-4} , but error correction and packet data transmission formats provide acceptable performance for many applications.

Limitations of these systems include lower data speeds and throughput rates and the requirement to obtain licenses for the radio channels. Most of the VHF and UHF radio spectrum allocated for this type of service is congested or assigned to mobile radio applications, making licensing in some areas difficult. They also require line-of-sight or near line-of-sight paths between the remote and the master station antennas, often requiring tall towers. Typical range of these systems varies from 10 to 40 km, which is a function of the operating frequency, intervening terrain, and height of the antenna systems. Despite their limitations, they are widely used in power-system data and SCADA systems because they can be designed to meet many *system priority* category communication requirements.

16.3.18 Power-Line Carrier

Power-line carrier (PLC) or carrier current systems transmit very low-frequency (65 to 300 kHz) radio signals over utility transmission and distribution wires. Although voice transmission is possible, most systems are used for telemetry and protective relaying. PLC systems provide a very reliable method of long-distance protective relay signaling for high-voltage transmission lines. More recently, distribution line carrier systems have been used successfully for automating distribution applications and automatic meter reading.

PLC systems can reliably transmit their low-frequency signals over transmission lines in excess of 200 km in length. Since existing transmission or distribution lines are used, no right-of-way or licensing is required. The primary limitation of these systems is their limited bandwidth, usually transporting two to four voice-equivalent channels. In addition, transformers and capacitor banks used for power factor correction severely attenuate the PLC signal.

16.3.19 Privately Owned Fiber Optic Cable Systems

Fiber-optic systems provide some of the highest quality transmission systems available with more capacity than any other telecommunications media today. Properly designed systems have extremely low bit error rates, on the order of 10^{-12} or better and capacities to 320 Gbits/s. Fabricated from very pure forms of glass, the hair-thin fiber strands are nonconductors, and thus not susceptible to the induced voltages and ground potential rise problems found in electric plant and substation environments. Fiber-optic cable is widely used for instrumentation, wide area networks and local area networks in and between the utility company's plants, substations, and offices.

Numerous utility companies are placing optical fiber cables (Fig. 16-17) in their electric-line rights-of-way. These can be used solely for internal communications, or excess capacity may be sold to other carriers. Specialized cable arrangements have been fabricated, suitable for the high-voltage transmission line environment.

There are several dozen variations of fiber-optic cable, protective sheath, and cable/messenger configurations used by utility companies on their electric transmission lines. A majority of the fiber being deployed on electric transmission line right-of-way today is in one of four arrangements. These include:

Direct Buried. An armored sheath protects a bundle of fibers. The sheath can be metallic or plastic.

Buried in Conduit. The conduit is usually nonconductive plastic or polyvinyl chloride style with two to four interior subducts. The multiduct conduit allows additional or replacement cables to be pulled into the duct system at a future date.

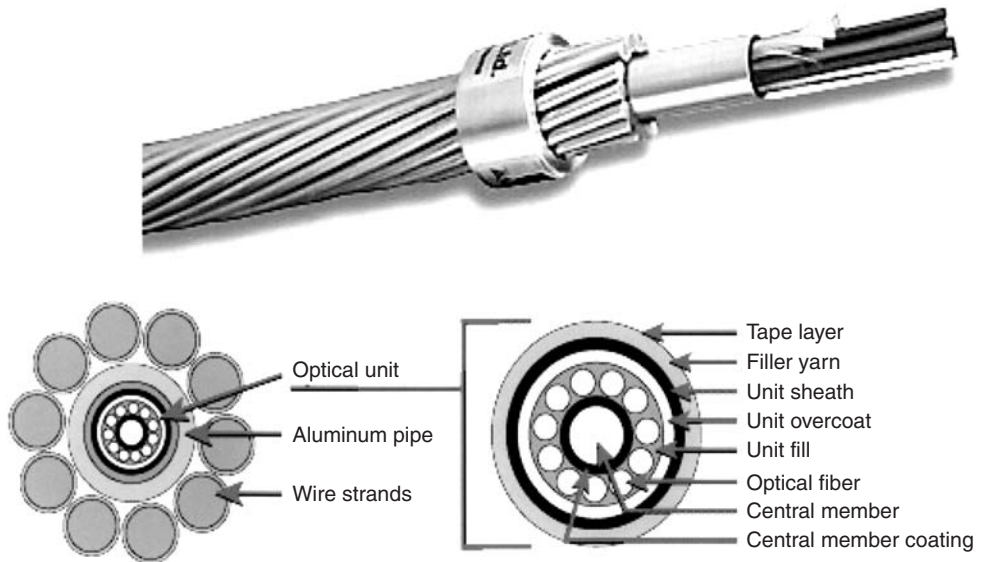


FIGURE 16-17 Optical ground wire.

All Dielectric Self-supporting Cable (ADSS). An aerial cable with a nonconducting protective jacket with Kevlar or fiberglass supporting members (Fig. 16-18). The nonconductive construction allows this type of cable to be placed close to the electrical conductors. This type of cable typically contains anywhere from 12 to 96 optical fibers.

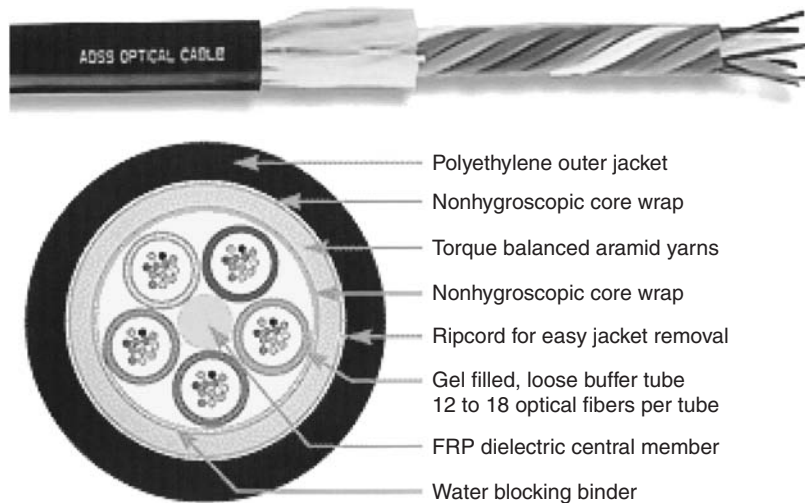


FIGURE 16-18 All dielectric self-supporting.

Optical Ground Wire (OPGW). The optical fibers are placed inside the metallic shield wire (also called a *static wire*) and suspended above the electrical conductors. In this application, the OPGW serves two functions: (1) it acts as a grounded shield wire protecting the electrical conductors from direct lightning strikes, and (2) it carries the fiber-optic communication cables. This type of cable is available with up to 144 fibers. Fiber counts above 96 fibers are less common due to the physical weight of the added fibers and support materials.

These wide area network fiber-cable systems use single-mode fiber cable, allowing distances up to 100 km without repeater stations. New fiber-optic cables and the application of optical amplifiers allow even greater distances. Most systems in service today transmit one or two optical wavelengths in the 1310 or 1550-nm regions. New technology allows multiple optical wavelengths to be transmitted over an individual fiber (wavelength division multiplexing), significantly increasing existing and future system's transmission capacity.

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16.4 INTELLIGENT DISTRIBUTION AUTOMATION

BY DOUG STASZESKY

Supervisory control and data acquisition has long been used to control transmission systems to provide the operational flexibility and speed, required for efficient and reliable performance. The use of SCADA in the distribution system is becoming increasingly important as utilities move into a deregulated, competitive environment. The acronym SCADA has been generally replaced by the term distribution automation (DA), which incorporates the principle of operating switching, fault interrupting, and other control devices automatically in response to events in the system. Automated switching of distribution feeder circuits provides significant improvements in reliability, enhances operational flexibility, and increases the utilization of distribution assets and personnel.

Feeder switching and protection systems utilizing powerful IED's, sophisticated algorithms, a plethora of sensing devices, and all connected by increasingly fast and secure data communications enable the implementation of distributed intelligence, which is fundamental to implementation of an intelligent grid now and in the future. As DA supplanted SCADA as the term *du jour* for such systems, it is likely that a new term IDA—intelligent distribution automation—will come to represent the real needs of utility planners, engineers, and operators to meet long-term customer needs as well as the demands of regulatory bodies.

Just as mainframe systems are being replaced with flexible, fast-distributed computing networks made of PCs, centralized control of the distribution power system will move to distributed computing to become the intelligent grid. The intelligent grid will deliver benefits far beyond that, which can be delivered by conventional reclosers, switches, automatic sectionalizers, and other devices, which do not share information about the status of the grid. Distributing system intelligence effectively eliminates communication bottlenecks and time delays associated with more conventional, centrally controlled SCADA systems, and are sustainable even if single computing nodes do not function. And, when properly designed, systems based on distributed intelligence offer a completely scalable advanced feeder automation system that can easily, and cost effectively meet the challenge

of the smallest tactical reliability problem, or grow to deliver system-wide automation functionality and improved asset utilization.

Distributed intelligence will become increasingly important as distributed energy resources (DERs) are deployed on the distribution system. Distributed energy resources, fully incorporated into the intelligent grid will further enhance reliability and power quality and have the potential to significantly improve overall asset utilization. Distributed energy resources are still in a state of growth and flux, so they will not be discussed in detail in this section. However, they are mentioned since it is likely that only an intelligent grid will be able to properly schedule a variety of distributed energy resources—and ensure that they operate safely in an interconnected grid. Intelligent Distribution Automation systems will enable a true “plug-n-play” environment, which will, in turn, truly enable the widespread use of DERs. Plug n play will also simplify system implementation for utilities.

Distribution automation systems today can also provide the means to optimize feeder and substation loading by enabling the shifting of load from one feeder to another in a very short time when needed. This same capability can yield hard dollar cost savings associated with deferment of capital projects when coupled with planning practices that take advantage of the new technologies.

Most importantly, distributed intelligence provides the tools that the utility planner will need to design a distribution system that will meet the increasing demand for reliability and power quality.

The following examples will demonstrate a wide range of system types available for IDA. Each discusses some of the benefits and drawbacks of each system and will provide a reference for the reader to consult when considering deployment of truly IDA on their system for reliability improvement, improved asset management, capital deferment, overtime reduction, improved knowledge of system conditions, and generally better customer service.

16.4.1 Automated Feeder Switching Systems

Recloser Loop Schemes. While they do not utilize distributed intelligence in the sense of intelligence shared via communication systems, recloser loop schemes are discussed because they are a fairly prevalent method for automating a system without the use of a central control logic.

Recloser-based systems typically rely on the idea that some percentage of faults on a system is temporary in nature. By reclosing some number of times for a temporary fault, sufficient time will go by for the fault to fall clear of the line and a subsequent reclosing operation will restore service. A permanent fault will not be cleared by the multiple reclosing operations and the device(s) trying to reclose will eventually lock open (lockout).

A typical line can be broken into two or perhaps three segments using multiple reclosers. The number of segments is typically limited by the ability to establish time overcurrent coordination between multiple reclosers such that only the last one before a faulted section operates to clear. A three-segment circuit would be fairly rare, as coordination would need to occur for, ultimately, four devices in series—the substation breaker, two normally closed reclosers, and, when a loop operates, a tie that would close—this typically proves quite difficult to do in practical application.

Reclosers rely on *local* overcurrent detection, voltage sensing and timers to effect restoration of the loop. When a fault occurs, the recloser immediately upstream of the fault will trip to clear the fault. It will then test the line through repeated application of fault current by reclosing a user-configured number of times. Reclosers downstream of a fault will sense loss of voltage and initiate a loss-of-voltage (LOV) timer. When the timer expires, normally open reclosers will open. A normally open tie recloser will close when its loss-of-voltage timer expires.

Recloser loop schemes typically consist of between fault interrupting reclosers, arranged in a simple loop. A 3-recloser, scheme is shown in Fig. 16-19. R1 and R3 are normally closed reclosers and R2 is a normally open tie between the two circuits.



FIGURE 16-19 3-reclosers loop scheme.

A fault between the substation SB D and R1, for example, will result in a trip of substation breaker D. It will reclose its configured number of times and will lock out for a permanent fault. R1 will sense the loss of voltage on its source and, upon expiration of its loss-of-voltage timer, will open. R2 will close upon expiration of its LOV timer and service will be restored to the unfaulted segment.

Should a permanent fault occur between R1 and R2, for example, then R1 will trip, reclose and lock out. Then, the normally open tie recloser R2 will automatically close into the fault after its loss-of-voltage timer expires in an attempt to restore service, but will trip and lock out. The unfaulted feeder emanating from substation breaker SB B will experience the fault current as well as voltage sag for all customers on the system.

Though such systems are often fitted with SCADA communication from the device back to the SCADA master station, there is no communication between devices and this type of system does not utilize distributed intelligence. Nevertheless, it is an effective way to automatically restore service to unfaulted segments and is easily implemented with little concern about communications.

But, such systems require that load capacity be reserved on each circuit to accommodate any load that may be picked up during a restoration sequence. This reserved capacity is typically based upon peak loading conditions and cannot account for actual time of day and seasonal load diversity factors. Therefore, for the bulk of the time that a circuit is not faulted, it is also an asset that is not being fully utilized.

Intelligent Loop Restoration Systems. Intelligent loop switching may use either switches or reclosers to effect automatic local sectionalizing of looped distribution circuits, then use distributed intelligence and peer-to-peer communications to effect automatic restoration of the system. A typical intelligent loop system using seven switches is shown in Fig. 16-20.

In the intelligent loop restoration system, each system switching device utilizes 3-phase voltage and current sensing to detect the passage of fault current and loss of voltage events following initiation of a fault. Each device also continuously monitors load for use in ensuring that loading limits are not exceeded during the circuit restoration process.

When a fault occurs, each device upstream of the faulted segment will see passage of fault current; each device downstream will see no fault current. All devices will see the loss-of-voltage condition when the upstream protective device operates. Logic dictates that the fault is in the line segment where the upstream switch sees fault current and the downstream switch does not.

The switching devices will open based on either counts of overcurrent or loss of voltage or upon expiration of a loss-of-voltage timer. Once this occurs, the distributed intelligence in each switch control will activate the restoration process. Based on knowledge of prefault loads in each segment and knowing the fault location, the intelligent restoration agent will close open switches only if the unfaulted segment can accommodate the load, and if the switch will not close into a faulted segment.

The use of ongoing voltage, current monitoring, and distributed intelligence ensures that the backup circuit will not be overloaded during the restoration process. This enables higher normal

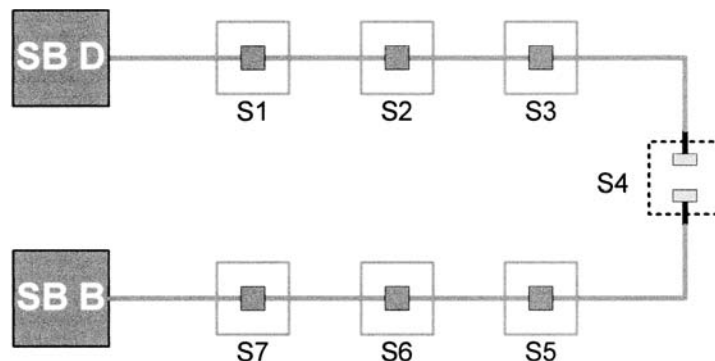


FIGURE 16-20 7-Switch intelligent loop restoration system.

loading than with noncommunicating loop schemes, which only accommodate load by reserving the capacity. Since real-time load monitoring is enabled, the system can take full advantage of load diversity, allowing restoration when able and preventing overload as needed. The result is that normal line loading can be increased to 75% of full-load capability or more depending on the amount of segmentation of the circuit.

And, distributed intelligence means that there will be no intentional closing of a device into a faulted segment. This significantly improves power quality for customers on the backup circuit when compared to a loop scheme, which intentionally closes the backup circuit into the fault.

An intelligent loop restoration system may use reclosers if proper coordination can be achieved with the desired number of circuit segments. If this is not possible, then switches may be used and the difference will be that more customers will be affected by momentary outages than with the all-switch case. Since intelligent loop restoration schemes are designed to complete the restoration process in less than 60 s, only the customers on the faulted segment of line will see an extended outage.

A side benefit of such schemes is the reduction in line patrol time—after all, a line crew travels to the patrol site at 50 mi/h, but performs the patrol at 5 mi/h. Getting to the faulted segment faster—and reducing patrol time means that restoration is faster—and overtime is potentially reduced.

Intelligent Multigrid Switching. In order to achieve significant jumps in both reliability and greater asset utilization than the systems described above, then a system must accommodate multiple sources. In this way, it is possible for some line segments to have more than one possible alternate source. The one-line shown in Fig. 16-21 consists of four circuits with multiple possible circuit ties through normally open switches.

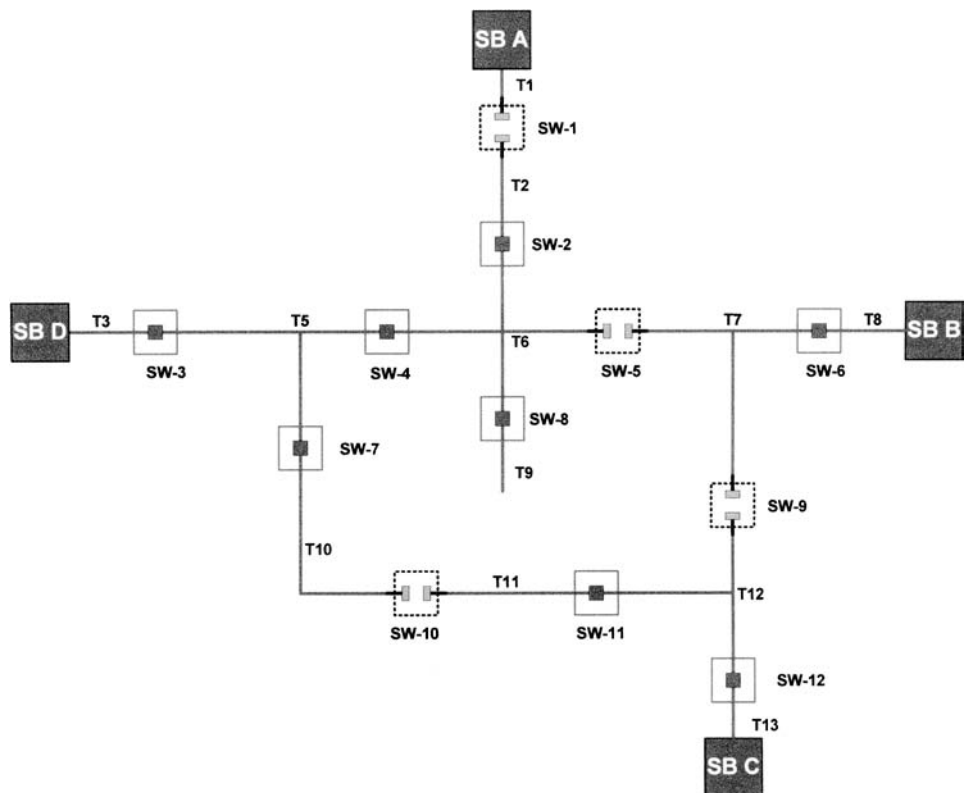


FIGURE 16-21 Intelligent multigrid system.

In the case above, all switching points utilize switches. Effecting time-overcurrent coordination between reclosers in such a system for both initial and contingency conditions would not be feasible due to the complexity of the circuit. For example, a large number of devices could wind up in series after a restoration process has been completed.

An intelligent multigrid system differs from an intelligent loop restoration system, primarily in complexity. The loop restoration system uses an overall circuit-logic approach where the entire system is treated as part of the intelligent restoration logic. The number of possible switching combinations that could come into play in a multigrid system requires a different approach.

The multigrid system breaks up the system logic such that it is resident in individual line segments bounded by intelligent switches (such as segment T6 in Fig. 16-21, which is bounded by four switches SW-4, SW-2, SW-8, and normally open SW-5). The use of a virtual agent assigned to each line segment, or team, can interact with neighboring virtual agents to effect intelligent system restoration using whatever sources are available for each de-energized segment, while still ensuring that the alternate source will not be overloaded when it is re-energized. Since the logic operates on a line segment basis, any number and type of segments can be connected to form an overall distribution system of virtually any size.

Other algorithms are used to allow for priority in choosing among multiple alternate sources when all other factors are equal. In this way, the user can force a certain amount of predictability in system operations to meet a variety of circuit planning criteria.

An example of this would be if a permanent fault occurred on line segment T5 in Fig. 16-21. In this case, substation breaker SB-D would trip, reclose, and eventually lock out. All switches on the circuit emanating from SB-D would open, either on overcurrent counts or loss-of-voltage counts. The intelligent multigrid restoration process would begin as soon as each line segment (team) confirms that the initial fault has been isolated. In the case of team T2, SW-1 will close after the agent in T2 confirms that the prefault load in T2 did not exceed the limit set for SW-1. The same process would be carried out by the agent in team T6; however, in this case, a priority has been set to restore load from team T2 first. Therefore, the process waits a predetermined time for SW-2 to become energized. The agent in team T6 then confers with T2's agent and should sufficient capacity be available to accommodate T6's prefault load, then SW-2 will close.

However, if sufficient load capacity does not exist in T2, then the agent in T6 will proceed to SW-5, where it will confer with T7's agent, perform the load analysis and close if capacity exists. Up to eight sources in a given team can be accommodated using this intelligent analysis.

If no priority is set, then the first available source with sufficient capacity will be used to restore service to a deenergized team.

The use of this distributed logic, in small, logical elements is essential for the construction of large and complex systems. Another advantage of this capability is that more than one contingency is accommodated, as long as alternate sources are available to a team for each subsequent line fault. Even if two of the sources in Fig. 16-21 were lost, some amount of load on any of the circuits could be restored using the remaining sources.

Intelligent multigrid systems do require robust communications, but the use of peer-to-peer radios or other communication devices, along with a segment-based logic will enable the restoration algorithm to function to some degree, even if some devices lose communications.

The other challenge to such a system is change. Such systems represent tools that were not available only a few years ago; conventional distribution circuit planning and design practices do not take full advantage of such systems, so a new way must be learned. However, once the ability to establish multiple circuit ties, safely and reliably, without overloading a system are incorporated into a utility design practice, then the ability to design to meet increasingly stringent customer and regulatory requirements is expanded greatly.

Intelligent Protection, Control, and Restoration Multigrid Systems. The intelligent multigrid system provides significant benefits, but requires operation of an "upstream" protective device—typically a substation breaker—to clear the initial fault. The next leap in function is to incorporate complete protection into such a system, thus eliminating outages for any but the faulted segments and beyond, for any given contingency.

Again, the use of a distributed, segment-based approach lends itself well to addressing both restoration and protection in any kind of circuit configuration. In this case, however, new algorithms and virtual agents must be used to accommodate adaptation of the protection system in addition to the comparatively straightforward restoration process outlined above.

Further, it is extremely advantageous to use highly accurate and fast protective devices and associated relays are required such that many applied in series are coordinated so that only the last device serving the faulted segment clears the fault. A method for fitting of curves based on upstream and downstream protective devices is needed—the curve-fitting agent that is responsible for this task.

This agent is also used to establish initial protective curves that provide coordination on the system in its normal state. As shown in Fig. 16-22, the curves for each substation breaker are not shown, but are designated A1, B1, C1, and D1. Protection curves for devices on the line are designated D2, D3, and D4, for example, with the higher number curve being faster than the lower numbered curve to establish a time-overcurrent coordinated system.

Once a restoration process has been completed, then the protection system must update itself to ensure that the protective coordination is maintained, regardless of the source from which a given segment is fed. An adaptive protection agent, working with the curve-fitting agent carries out this task.

In the case shown in Fig. 16-22, a loss of the source to substation SB-D will result in initiation of a restoration process, which will open the normally closed interrupting devices, then close open points, after checking for load capacity and absence of fault indication on a segment. Note that it is assumed that there is no communication between any of the field fault interrupters and the substation breaker relays.

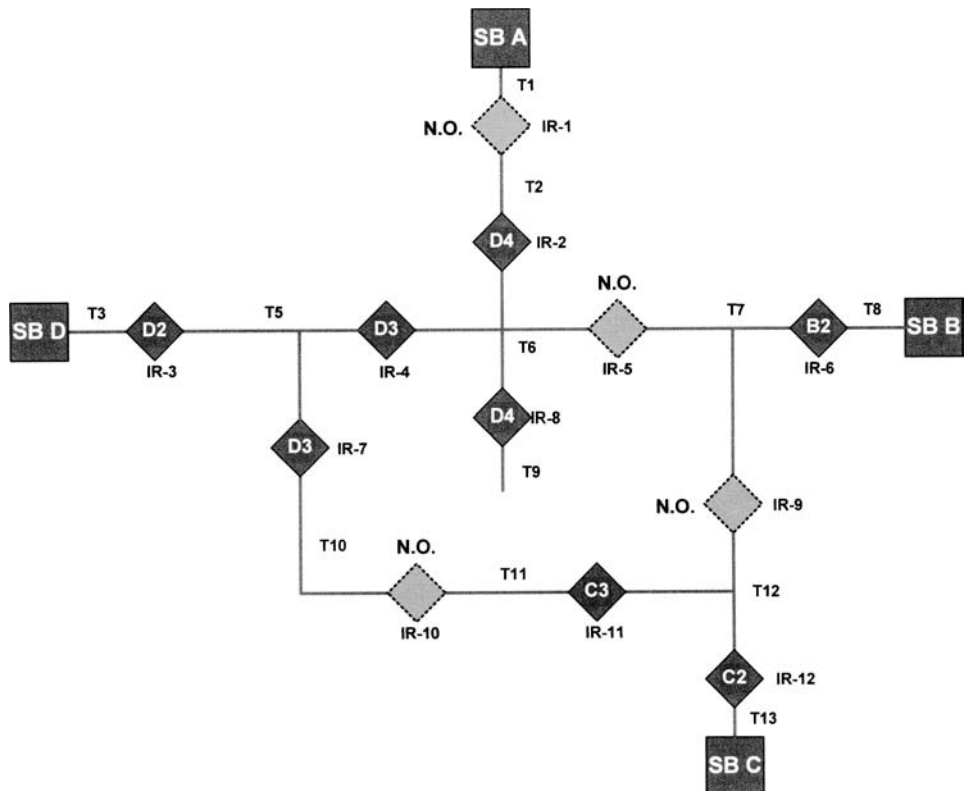


FIGURE 16-22 Intelligent protection, control and restoration multigrad system.

One possible result is for a new circuit to be configured, emanating from SB-C, feeding through IR-12, IR-11, IR-10, IR-7 and then to new open points at IR-3 and IR-4, as shown in Fig. 16-23. Using an adaptive coordination algorithm, each interrupter will talk to its upstream counterpart to ensure that it either has a faster protection setting or the same protection setting as its upstream neighbor.

It is noted that there may not always be sufficient room between protective curves for direct time-overcurrent coordination. In this case, devices must share a common curve. When this condition occurs, coordination is still possible using high-speed communications to effect coordination between devices using a blocking and adaptive coordination, process, whereby all devices that detect fault current passage signal their upstream neighbors. Interrupters that receive the signal increment their protection curve slower by 1.

For example, if a fault were to occur in segment T5 in Fig. 16-23, then interrupters IR-7, IR-10, IR-11, and IR-12 would detect the fault. Since the system uses distributed intelligence, the coordination agent knows that IR-7 and IR-10 share curves and that IR-11 has a setting of C3 which coordinates with C4. Therefore, only the interrupters with shared curves will utilize communications-based coordination. When the fault occurs, IR-7 will detect the fault and send a signal to IR-10. IR-10 will wait a small amount of time and when the signal is received, will decrement to curve C3. C4 did not receive any signal from a downstream device; therefore, it remains at C4. C4 is faster than C3 and all upstream curves; therefore, it is the only device to operate, thus clearing the fault in T5 in a coordinated fashion.

The intelligent protection, control, and restoration multigrad system combines the advantages of fault-interrupting devices while using distributed intelligence to overcome the difficulties in applying such fault-interrupting devices in complex circuit configurations. All the while, such a system also

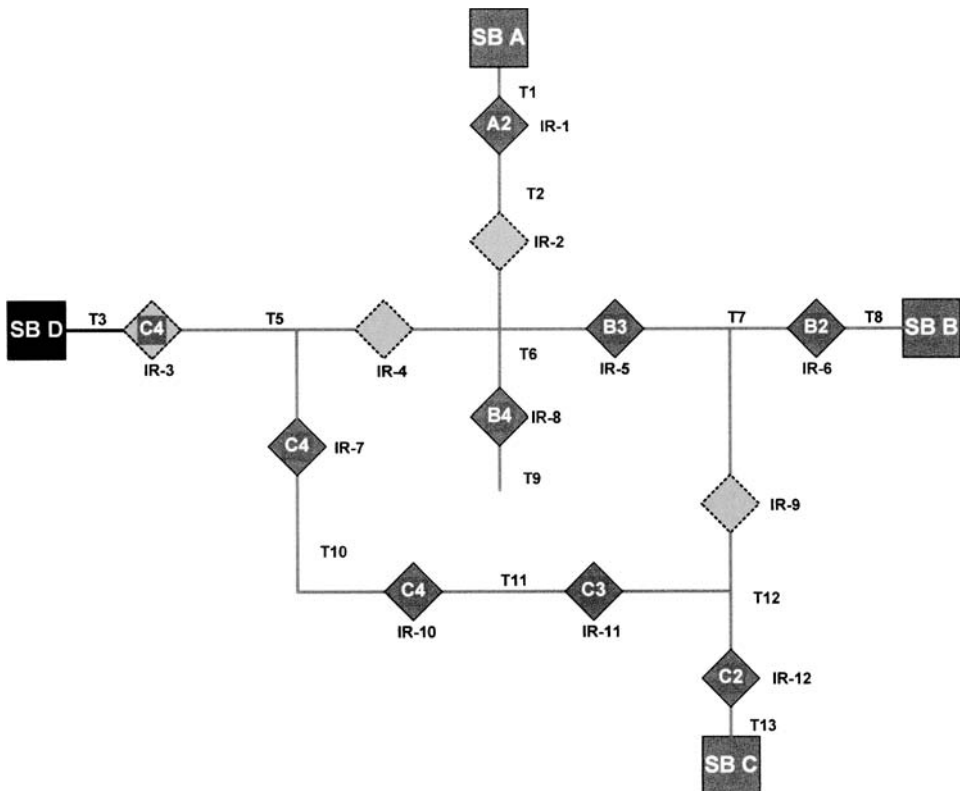


FIGURE 16-23 Reconfigured state of example system.

monitors circuit loading to prevent inadvertent overloading, thus delivering the improved asset management benefits of the intelligent multigrid switching system.

16.4.2 Summary

Each of the circuit protection and restoration systems described in this section are available in the industry as of the writing of this book. It is clear that some are easy to apply, but deliver only simple benefits. The more complex and modern a system is, the more benefits it can provide. But, it also requires a shift in thinking about circuit planning and design to maximize those benefits.

In the end, the use of highly intelligent devices on the distribution feeder—in circuit configurations that are probably difficult for many of us to even conceive of today—will be the answer to meeting the ever-increasing needs of users of electric power. Such systems will also, ultimately, reduce utility workload by moving the operating decisions to an intelligent, distributed system, taking full advantage of advances in computing and communication technologies on an ongoing basis. This will leave utility engineers and planners free to be more creative in their designs.

16.5 IMPACTS OF EFFECTIVE DSM PROGRAMS

By HESHAM SHAALAN and CHRISTA LORBER

16.5.1 Introduction

Demand-side management (DSM) is proving to be a viable means by which utilities can meet their load-shape objectives. Two decades of studies, projections, and pilot programs are suggesting that DSM can be cost-effective and flexible. Demand-side management programs have the potential to target diverse areas of end-use electricity consumption, thus deferring the need to meet growing demand through added capacity. From the utility's perspective, this promotes cash flow that would otherwise be tied up in capital investments and costs. From the customer's perspective, these programs provide incentives that range from lower electricity rates to rebates on the purchases of more efficient appliances and equipment. Therefore, there are benefits which are attractive to both parties. However, another important benefit of DSM is preserving the environment. Electricity reductions that proceed from DSM programs translate into savings by curtailing and delaying the environmental impacts for which pollutants and greenhouse gas (GHG) emissions are greatly responsible.

Commercial-sector DSM programs provide significant options for utilities in meeting growing demand. This section provides an estimation of savings in cost as well as projected GHG emissions based on effective DSM programs in the commercial sector. Realistic estimates of savings based on actual results from two previous utility studies will be presented.

Most electric utility systems in the United States were designed to account for some daily, weekly, and seasonal variability in load. This variability is desirable from the planned maintenance point of view. To account for the fluctuations that occur, different types of generating facilities are used together in various combinations to minimize total costs. This is necessary because the electric utility industry is quite capital-intensive. For every \$1.00 of revenue, the utility industry requires \$3.50 of capital, compared with the average industry, which needs only \$0.80 per dollar of revenue.¹ Aside from the moderate fluctuations in demand, electric power is most efficiently produced when changes in the total system load are kept as small as possible. Ideally, the ratio of average power to peak power, or *load factor*, should be kept high. Interestingly, DSM provides opportunities through which utilities can achieve increasing power-system load factors.

16.5.2 Commercial-Sector DSM

Demand-side management encompasses a variety of activities that influence the pattern and magnitude of a utility's load. Programs are geared to meet one of six main objectives depending on whether the

utility is targeting residential, industrial, or commercial customers, since the load curves for each of these sectors vary considerably. The objectives utilities set to change their load shape include peak clipping, valley filling, load shifting, strategic conservation, strategic load growth, and flexible load shape.

Of the preceding six objectives, peak clipping for the commercial sector is of overwhelming interest to power utilities and distribution cooperatives alike. The reason for this is historical. Using existing plants more effectively is preferable over building a new plant. For example, peak clipping makes the power system more reliable, alleviating the need for a peak-load plant that is expensive to run and only necessary 10% of the time to meet peak demand.¹ Moreover, the commercial sector has been the most rapidly growing sector in terms of electricity sales and peak. In fact, between 1970 and 1990, the sales gain for this sector averaged about 24 billion kWh per year, which is 36% of the total gain.² Although sales gains over the course of the next two decades are expected to be halved in comparison, electric utilities still have to contend with the increases. For these reasons, commercial-sector DSM programs provide significant options for utilities in the determination of how they will meet growing demands.

16.5.3 Effective DSM Programs and Their Impacts

For most commercial buildings, lighting and air conditioning comprise 70% of electricity consumption, where lighting accounts for 40% and air conditioning accounts for 30%.³ Such predominance provides opportunities for significant savings that could result from well-planned programs targeting these two consumption types.

Lighting Control Program Savings. Commercial customers perceive lighting as a necessary, fixed load because inadequate or ineffective illumination hampers productivity and sales. Therefore, lighting can be classified as a predictable load from the utility's point of view. Thus, lighting control is a viable candidate for DSM programs which promote increased penetration of energy-efficient lamps and ballasts.

To exemplify the magnitude of savings that can occur, a case in point is essential. Consolidated Edison Company of New York (Con Edison), one of the largest electric utilities in the country, sponsored an Enlightened Energy Rebate Program beginning in 1991 which provided cash rebates for both retrofit and new installations of high-efficiency lighting. Five years of pilot programs precluding the Enlightened Energy Rebate Program provided the experience on which to anticipate success. Con Edison's goals were twofold in promoting the energy rebate. The first objective was to reduce the load on certain transmission and distribution (T&D) equipment, a very cost-effective goal, since increasing T&D capacity in the New York area is quite expensive. The second objective was geared toward increasing profits via incentive rates of return approved by the New York Public Service Commission. Rewards were granted for energy savings rather than capacity reduction; however, in the process of striving for the kWh savings, significant peak reductions occurred. In fact, Con Edison is projecting peak reductions of 22% to 23% by the year 2008.⁴

The Enlightened Energy Rebate Program was offered to 40,000 commercial customers, 2744 of which participated. The verified reductions in 1991 were 157.9 MW of electricity and 241 million kWh.⁴ Table 16-1 translates these energy savings into

TABLE 16-1 Projected Emission and Cost Savings: Consolidated Edison Enlightened Energy Program

Millions kWh	241
CO ₂ (thousand tons)	173
SO ₂ (tons)	343
NO _x (tons)	187
CO (tons)	24.3
VOCs (tons)	2.76
Total cost (million dollars)	4.05
Electricity (MW)	157.9

emission savings in terms of quantities and associated costs. The assumptions used in calculating these values are provided in the Appendix along with sample calculations. The total cost is dominated by the CO₂ and SO₂ emission savings, which amount to \$2.35 million and \$1.39 million, respectively.

Air-Conditioner Control Program Savings. Load control is likewise a DSM program with the potential to achieve significant penetration in the commercial sector. Currently, tens of thousands of commercial facilities have been retrofitted or were originally constructed with

building energy management and control systems. Weather-sensitive loads often account for the highest peaks in demand seen by utilities, thereby degrading their annual load factors. As a result, these types of loads are excellent load-control candidates. Studies indicate that air conditioners represent the most commonly controlled commercial load.³ This implies that improved load factors and considerable savings can be realized by air-conditioner control programs.

Available load research data and a previous air-conditioning load management program¹ sponsored by Arkansas Power and Light (AP&L) provide an opportunity to quantify savings for the commercial sector of hot springs. The previous air-conditioning load-control program took place during the summers of 1975 and 1976 and targeted two residential areas to determine the economic feasibility of interrupting central air-conditioning units for short periods of time during peak-load periods. The monitoring of this particular pilot program was implemented using a Motorola radio system with a remote-controlled switch during the hours of 1 to 5 P.M. from June 15 through September 15. Because this was a pilot program, AP&L had several objectives concerning program effectiveness. The first involved determining the contribution of a single unit to peak demand and the amount of air-conditioning load which could be displaced during the system peak-load periods. Determining the threshold of customer inconvenience incurred through implementing control during the peak periods was the second objective. The third focus of the investigation was the feasibility and reliability of a radio-controlled system.

The incentive to the participating customers included a \$2.00 return per kVA of air-conditioning capacity per month, free service inspection on the air-conditioning system, and a guarantee that the system would be restored to its pretest condition should any damage result. The results from this test were exceedingly favorable. Each residential central air conditioner contributed 4 kW to the system peak and could be switched off 15 min out of each hour without causing the customer discomfort. A peak-load reduction of 1 kW per unit resulted from this control action. In addition, the tests established that radio control was a viable means of shedding loads during peak conditions. More than 25,000 residential radio switches were installed at the end of 1978, with additional installation plans of 25,000 per year until reaching the saturation goal of 125,000.

Encouraged by the air-conditioning load-control success within the residential sector, AP&L reported plans to extend air-conditioner load control to its commercial sector. In so doing, the average peak demand reduction amounted to 1.6 kW per unit.³ Figure 16-24 shows the load curve for the month of July generated from AP&L commercial data. The dotted line represents the effect that air-conditioning load control would have if each unit were reduced by 1.6 kW. The kWh savings result from load control between 12 noon and 6:00 P.M. Due to the difference in load shape between the

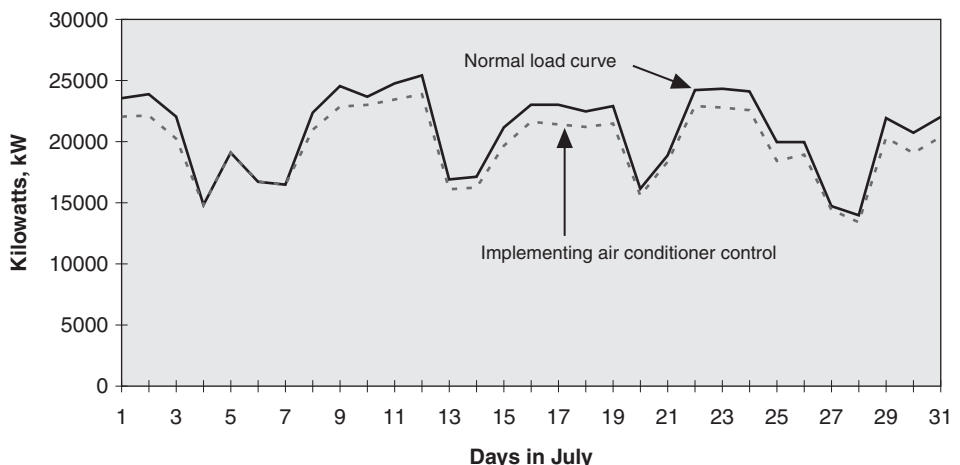


FIGURE 16-24 Load curve for the month of July.

TABLE 16-2 Projected Emission and Cost Savings for July Research Load Data: Arkansas Power & Light Commercial-Sector Air-Conditioner Control

Thousands kWh	248
CO ₂ (tons)	178
SO ₂ (tons)	0.353
NO _x (tons)	0.192
CO (tons)	0.025
VOCs (tons)	0.003
Total cost (dollars)	4,173
Electricity (MW)	0.248

in air-conditioning load control. In addition, the season for commercial-sector air conditioning is considerably longer than for the residential sector. Thus, significant emission savings are attainable with increased participation for a full season.

residential and commercial sectors, the control had to be extended by 2 h in order to effectively shed peak load. Despite the additional 2 h of control, the assumption of a 15-min/h shut-off cycling period remained consistent with the residential control program.

Load data for the month of July was used in Fig. 16-24 because this is the hottest month during which AP&L must provide services. Table 16-2 quantifies the savings that result from air-conditioner control for the month of July, as seen in Fig. 16-24. Once again, CO₂ and SO₂ dominate the total cost savings. CO₂ contributes \$2421 to the overall \$4173, while SO₂ contributes \$1433. Although the reported emissions seem relatively small, the results of Table 16-2 represent a mere 1.3% of the potential commercial customers eligible to participate

16.5.4 Projected Total DSM Program Impacts

Table 16-3 illustrates how all cooling and lighting programs within the commercial sector will impact the environment over the course of the next two decades. The figures reported in the table give combined totals of cooling and indoor/outdoor lighting; however, the lighting contribution is almost twice that of the cooling.

The savings in kWh, emissions, and cost reported in Table 16-3 are evidence of the effectiveness of DSM strategies. By the year 2000, CO₂ emission savings will be above 35 million tons, which alone accounts for \$486 million. The electricity and added capacity savings is phenomenal, both short and long term. By 2020, savings will be more than twice that occurring in the year 2000. SO₂ and NO_x emission savings are likewise quite sizable, providing evidence that conservation and preservation can occur with DSM.

16.5.5 Conclusion

Of the many DSM programs that could enable utilities to operate efficiently, lighting and air-conditioner load control are two proven methods by which utilities can reduce their peak and provide savings for themselves, their customers, and the environment. To be effective, a program must be well planned. Therefore, successful programs are usually preceded by a pilot program to ensure

TABLE 16-3 Total Lighting and Cooling Emission and Cost Savings

	Year		
	2000	2010	2020
Billions kWh	4.98	8.50	10.9
CO ₂ (million tons)	35.7	61.0	78.1
SO ₂ (thousand tons)	70.8	121	155
NO _x (thousand tons)	38.6	66.0	84.4
CO (thousand tons)	5.00	8.55	10.9
VOCs (thousand tons)	0.570	0.973	1.25
Cost (million dollars)	837	1430	1830
Electricity (GW)	66.1	113	145
Added capacity (400-MW plant)	165	282	362

TABLE 16-4 Emission Characteristics of Power Plants in the United States (g/kWh)

Plant type	VOCs	CO	NO _x	SO ₂	CO ₂
Gas	0.025	0.20	1.00	0.004	490
Oil	0.050	0.19	1.00	5.08	781
Coal	0.010	0.11	1.00	2.00	1030

that the utility's objectives can be met. Furthermore, a utility must build a good relationship with its customer base. Otherwise, future DSM programs may be jeopardized. This can be achieved through frequent customer contact and by giving the customer some decision-making provisions. Support services necessary to a particular DSM program should be established prior to the effective starting date. This is essential in order to monitor the program accurately. Without adequate preparation, gathering data and keeping up with customer inquiries are virtually impossible.

The purpose of DSM is to improve what already exists and make what is new as efficient as possible. Meanwhile, the utility's reputation is at stake. For this reason, a major focus of these programs is the customer. In the process of promoting energy efficiency and establishing trustworthy relationships, it may be easy to overlook environmental impacts and savings. Therefore, any precautionary action that may minimize environmental changes has additional value beyond successful programs and satisfied customers. Thus, it can be argued that sustenance is the hidden value of DSM.

APPENDIX

Assumptions. The information provided herein focuses on the manner in which the values reported in Tables 16-1, 16-2, and 16-3 were calculated. Some basic assumptions have been made in order to obtain those results:

1. Coal has a 70% carbon content.
2. A 400-MW coal plant uses 800,000 MT of coal per year.
3. CO₂ recovery equipment has a 90% removal efficiency.
4. The emission characteristics of power plants in the United States (g/kWh) are shown in Table 16-4. The values shown assume a mix of 10% combustion turbines and 90% steam turbines.
5. The cost of pollutant per ton emitted is shown in Table 16-5.

TABLE 16-5 Cost of Pollutant per Ton Emitted

Pollutant	Cost (\$/ton)
CO ₂	13.60
SO ₂	4060
NO _x	1640
CO	82
VOCs	300

Sample Calculations

• Emission*

Tons of pollutant:

$$(\text{year kWh}) \times (\% \text{ generated electricity}) \times [\text{emission characteristic (g/kWh)}] \times (\text{conversion factor})$$

Example Savings of Total SO₂ Emissions

Gas	Tons SO ₂ = (4.98E + 10) × (0.119) × (0.004) × (1.1E - 6) =	26.10
Oil	Tons SO ₂ = (4.98E + 10) × (0.039) × (5.080) × (1.1E - 6) =	10,866.76
Coal	Tons SO ₂ = (4.98E + 10) × (0.546) × (2.000) × (1.1E - 6) =	59,895.52
	Tons total	70,788.38

*Note that this calculation is performed for all substances listed in the preceding table.

- *Cost*
Total cost

$$(\text{Total emissions}) \times (\text{cost of pollutant})$$

Example *Total SO₂ Cost Savings*
 $\text{Cost (million \$)} = (70,788) \times (4060) = 287$

- *Electricity and added capacity savings (based on CO₂ emissions)*
Added Capacity Savings

$$(\text{CO}_2 \text{ emission savings})/(\text{tons of CO}_2 \text{ emitted from 400-MW plant})$$

Electricity (that could be produced with neutral GHG effect)

$$(\text{Added capacity savings}) \times [\text{size of plant (MW)}]$$

Example

$$\begin{aligned} \text{Tons of CO}_2 \text{ emissions} &= (800,000) \times (2.57) \times (0.1) = 216,000 \\ \text{Added capacity savings (No. of 400-MW plants - year 2000)} \\ &= (35,700,000)/(216,000) = 165 \\ \text{Electricity (GW)} &= (165) \times (400) = 66.1 \end{aligned}$$

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